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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

ROBERT BURNS, Chairman
BOYD DUNN
SANDRA D. KENNEDY
JUSTIN OLSON
LEA MÁRQUEZ PETERSON

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01345A-19-0236 **ARIZONA PUBLIC SERVICE COMPANY'S NOTICE OF FILING**

APS provides notice that it is filing the attached rebuttal testimonies of Mr. Jeffrey Guldner, Ms. Barbara Lockwood, Mr. Brad Albert, Ms. Elizabeth Blankenship, Mr. Jacob Tetlow, Ms. Jessica Hobbick, Mr. Leland Snook, Ms. Monica Whiting, Dr. Ronald White, Ms. Ann Bulkley, and Mr. Todd Shipman as Attachments 1-11, respectively.

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RESPECTFULLY SUBMITTED this 6th day of November 2020.

By:/s/ Melissa M. Krueger
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ORIGINAL electronically filed
this 6th day of November 2020, with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
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ATTACHMENT 1

REBUTTAL TESTIMONY OF JEFFREY B. GULDNER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-19-0236

November 6, 2020

Table of Contents

REBUTTAL TESTIMONY OF JEFFREY B. GULDNER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-19-0236)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Jeffrey B. Guldner. I am Chairman of the Board and Chief Executive Officer (CEO) of Arizona Public Service Company (APS or Company). My business address is 400 N. 5th Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS MATTER?

A. Yes. I filed direct testimony on October 31, 2019.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. It is important to address several recommendations made in this case that would materially impact APS's ability to serve its customers and communities, while also meeting our financial obligations to investors. My Rebuttal Testimony explains how adoption of such recommendations could jeopardize our mission of providing clean, reliable, and affordable electric service to 1.3 million customers, and why the Arizona Corporation Commission (Commission) should reject them. In this context, I believe that it is important to call out the steps we are taking to mitigate rate impacts on customers.

I also discuss APS's Clean Energy Commitment and some of the implications of achieving that commitment, specifically, the need to maintain customer affordability and assisting affected local communities through a transition away from coal generation. I describe a new adjustor mechanism to address these implications through transparent and timely recovery of the Company's investment in supporting a clean energy future for Arizona.

Finally, my Rebuttal Testimony will explain our approach to executive-level compensation, and why it appropriately supports the need to attract and retain a highly qualified management team.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Over the past year, my first as Chairman of the Board and CEO of APS, I have appeared before the Commission on numerous occasions to reaffirm our commitment to customers and articulate a vision for APS anchored in purpose: as Arizona stewards, we do what is right for the people and prosperity of our state. As such, I pledged to be transparent, collaborative and inclusive of stakeholder perspectives in our decision-making process. I have taken ownership of issues related to customer service and communication outreach, while driving culture change efforts internally to create a sustained customer experience mindset across our workforce. Our Clean Energy Commitment thoughtfully balanced stakeholder input, operational reality and customer affordability to target 65 percent clean energy, inclusive of a 45 percent renewable goal by 2030 on our way to 100 percent clean by 2050. And, at the same time, APS remained focused on providing reliable service and support to our customers throughout a year unlike any other in recent history. Each one of our 6,200 employees shares this call to serve and operates with a unified sense of purpose.

The reality is, however, that providing reliable electric service, achieving a clean energy future and supporting state and local economies are dependent upon the financial health and long-term sustainability of the Company. We must remain attractive to investment of outside capital so that we can secure the significant amount of resources required to simultaneously maintain and modernize the electric system.

Some intervenors in this case would significantly reduce or even eliminate the Company's base revenue requirement, slash returns on equity to unreasonably low levels, deny returns on the fair value of utility property, and disallow the recovery of amounts that have been prudently incurred for facilities that are used and useful. If adopted, those recommendations individually and collectively will impair APS's ability to pay for its current operations and future commitments and send strong signals that any equity investment in the Company is at risk of not recovering a stable return.

These outcomes are unnecessary, contrary to the best interest of our customers, and unwarranted based upon the information that supports the Company's rate application in this case. I trust the Commission to apply sound regulatory principles in granting the Company's rate request and to reject any outlying and punitive recommendations made by certain intervenors that will ultimately harm Arizona.

III. <u>THE IMPORTANCE OF FINANCIAL STABILITY</u>

Q. WHY IS IT IMPORTANT THAT APS BE FINANCIALLY STABLE?

A. APS's filings in this case demonstrate that it is not earning its currently authorized return on equity. APS depends upon the revenue generated from its rates to operate APS and provide safe and reliable service to our customers. Also, because rates are set on a historical test year in Arizona, APS looks in large part to our investors to fund capital and other projects until such time as the Commission authorizes their recovery through rates and those rates are collected.

If rates are set that do not meet APS's revenue requirement, the Company's ability to fund its operations and commitments is seriously jeopardized. This in turn forces the Company to make decisions regarding which programs will be funded and at what levels. As always, safety and reliability take precedence in those instances.

When rates are based upon artificially low returns on equity or cost of debt, investment capital in the utility either dries up or becomes very expensive. This is equally true when unconventional steps such as the disallowance of prudently invested funds or the costs of used and useful facilities are excluded from rates.

APS competes for investment capital in international and national markets, where there are countless options. Investors in any utility rely upon the basic regulatory principle that prudent investments and costs will be recoverable when they go into service. Without reasonable and competitive returns on those investments and timely recovery of prudently incurred costs, APS becomes a less attractive choice for investors and lenders. The Company's financial health greatly impacts the amount and cost of the borrowed funds. The lower the cost of borrowing funds, the lesser the impact on our customers' bills. Through working collaboratively with the Commission and stakeholders towards stable, beneficial regulatory outcomes, APS's improvement in credit ratings since 2011 has created pre-tax interest savings on APS long-term debt issuances of nearly $2 billion over the lifetime of the debt. I cannot overstate the importance to our customers and communities, as well as our future initiatives, that the Commission support the financial viability of the Company through the approval of this rate request.

IV. MITIGATING RATE IMPACTS

Q. WHAT IS APS DOING TO MITIGATE THE RATE IMPACTS FOR ITS CUSTOMERS?

A. The impact of rate increases on our customers is a matter of concern for all of us. We are addressing this issue at many levels in the Company and with our stakeholders. As discussed in the testimonies of APS witnesses Monica Whiting and Jessica Hobbick, APS is committed to expanding eligibility for its limited-income discount program (Rate Riders E-3 and E-4, Energy Support Programs) and working with Wildfire and government agencies to ensure that the discount as well as Crisis Bill funding is available to those in greatest need. I will also mention two additional Company-wide initiatives that are aimed at reducing rate increase impacts. Last year the Company committed to the Commission that we would reduce APS operating and maintenance costs by $20 million, and proactively included a pro forma in the application reflecting those targeted savings. I am pleased to report that we are on track to achieve that reduction and that this level of savings is included in this rate case.

APS has also undertaken a thorough initiative to streamline processes and empower employees to implement more efficient and economical ways to work on an ongoing basis. I am confident that these and other efforts will not only continue to reduce costs going forward, but also provide for an improved and innovative workplace and experience for our customers.

V. APS'S CLEAN ENERGY COMMITMENT

Q. APS ANNOUNCED A COMMITMENT TO CLEAN ENERGY IN JANUARY OF 2020. WHAT DOES THAT CONTAIN?

A. We already provide 50 percent of our energy from clean, carbon-free generation resources and have been on a trajectory of increasingly clean energy through solar power innovation, wind power, major investments in energy storage technology, carbon-free nuclear operations, and advances in energy efficiency and demand response solutions.

In January of this year, we made a commitment to Arizona. By 2050, APS will deliver 100 percent clean, carbon–free, and affordable electricity to our customers. This goal includes a nearer–term 2030 target of 65 percent clean energy, with 45 percent of our generation portfolio coming from renewable energy.

We also will cease all coal–fired generation by 2031, and will make this transition in a responsible manner, working closely with the affected communities to minimize impacts and help identify new opportunities. Our commitment to them is for the long-term.

Our Clean Energy Commitment represents the boldest clean-energy goal of all Arizona electric utilities and one of the most ambitious in the country. And while there is no doubt in my mind this is the right move for our Company, customers and communities, the road to 100 percent carbon-free comes with unique challenges. These include keeping rates affordable for customers, assisting communities that are severely impacted by the closure of coal facilities and maintaining a financially healthy Company. Only by meeting all of these challenges can we enable the pursuit of a shared, clean energy vision for Arizona.

A. *Balancing Clean Energy and Costs to Customers*

Q. IS APS CONSIDERING ANY WAYS TO MITIGATE THE COST TO CUSTOMERS FROM THE COMPANY'S CLEAN ENERGY COMMITMENT?

A. Yes. To be clear, the first five to seven years on this path involve significant costs associated with the transition away from traditional, carbon-emitting fuels to clean energy infrastructure. And although the latter eventually brings significant societal benefits and lower fuel costs, APS is exploring several strategies to mitigate the upfront transition costs and ensure rate gradualism during the shift to a new energy economy. As discussed more fully in the testimonies of APS witnesses Barbara Lockwood and Leland Snook, APS is proposing an Advanced Energy Mechanism (AEM) that would be used to recover the costs associated with the significant clean energy investments the Company will be making to meet its Clean Energy Commitment. APS is also committed to pursuing securitization for retiring assets, which could be used to help lessen customer rate pressures.

Q. PLEASE EXPLAIN WHY APS IS SEEKING AN AEM.

A. In connection with our Clean Energy Commitment, we are proposing a mechanism to track and provide timely recovery for, among other things, the capital carrying cost and expense of clean energy investments. It could include energy efficiency (EE) expenses, and lost fixed costs associated with EE and distributed generation (DG) revenue requirements that are not already recovered in base rates or through another Commission approved adjustor. APS witness Snook, Director of Rates and Rate Strategy, will address the proposal in more detail. The AEM is designed to be a simplified, transparent and timely way to monitor and collect the costs and expenses of clean energy related investments going forward.

Q. CAN APS MEET THE CLEAN ENERGY COMMITMENT WITHOUT SUCH AN ADJUSTMENT MECHANISM?

A. It would be very difficult. While we are committed to our pursuit of a clean energy future, without this mechanism or something equivalent, progress in this transition will be slowed, creating a significant burden on the Commission, the Company and intervenors due to the frequency of rate cases required to recover investments. Further, meeting our clean energy commitments without contemporaneous recovery will pressure the credit quality of the Company and, consequently, our credit ratings. The Company's credit quality is critical to raising capital at low cost for the benefit of our customers. As APS witness Todd Shipman will further explain, the credit rating agencies have identified timely cost recovery as central to their ratings methodologies and view adjustment mechanisms as important risk mitigants, particularly during periods of elevated investment levels such as our clean energy commitments will require.

Q. PLEASE BRIEFLY EXPLAIN THE CONCEPT AND POTENTIAL BENEFITS OF SECURITIZATION.

A. Generally, securitization of retiring assets, combined with an adjustor mechanism, are tools that can reduce the rate impacts of transitioning to a clean energy future. Securitization provides a balance by reducing the amount paid for these assets and providing a method for the utility to invest in clean resources – a balance that has been successfully adopted in several jurisdictions across the country.

Q. HAS SECURITIZATION OF UTILITY ASSETS BEEN UTILIZED IN ARIZONA?

A. No, not yet. As discussed more by APS witness Lockwood, we believe that there is new legislation needed to enable securitization to move forward. Securitization is a complex topic, and it needs to be done appropriately to provide the intended benefits to all parties. APS is committed to pursuing securitization and looks forward to working with the necessary parties to make it happen in the interest of our customers.

B. *Coal Community Transition (CCT)*

Q. PLEASE EXPLAIN APS'S COMMITMENT TO ASSISTANCE IN CONNECTION WITH THE CLOSURE OF COAL-FIRED UNITS.

A. As part of the Clean Energy Commitment, we pledged to end coal-fired generation by 2031, seven years earlier than we had previously announced. This is an important step toward our goal of 100 percent clean energy resources by 2050. However, the closure of coal-fired power plants and the reduction in coal consumption will have a negative economic impact on those communities whose economies are dependent upon those plants and mines. Through discussions with these communities, APS has come to a thoughtful, meaningful agreement to assist this transition.

Q. PLEASE DESCRIBE THE TRANSITION COMMITMENT TO THE NAVAJO NATION REGARDING THE EVENTUAL CLOSING OF THE FOUR CORNERS POWER PLANT.

A. One of the communities that will be hardest hit economically by the plant closures is the Navajo Nation. We have engaged in discussions with representatives of the Navajo Nation to better understand the impacts of the closures and the needs of those communities, as well as potential opportunities for assistance from APS going forward. APS proposes a total of $128.75 million in funding for this transition, which includes $23.75 million from shareholders. This commitment is discussed in more detail by APS witness Lockwood, and includes $110 million over ten years for a transition, as well as funding for electrification efforts, transmission development and regional economic development efforts.

Q. HAVE THERE BEEN DISCUSSIONS TO BUILD A CLEAN ENERGY PROJECT ON NAVAJO NATION LAND?

A. Yes. As part of this agreement, which is also discussed in more detail by APS witness Lockwood, APS commits to seek out proposals for at least 600 MW of clean energy projects on or near the Navajo Nation.

Q. IS APS PLANNING TO ALSO ASSIST OTHER COAL COMMUNITIES AS PART OF THIS OVERALL COMMITMENT?

A. Yes. In regard to the Cholla Power Plant, APS is proposing $12 million to neighboring Navajo County communities to assist in a transition, including $1.1 million dollars in shareholder funding.

Also, APS is proposing $3.7 million, including $0.35 million in shareholder funding, for a transition plan for the Hopi Tribe in conjunction with the closure of the Navajo Generating Station in 2019.

Q. DO YOU HAVE ANY FINAL COMMENTS ON CCT?

A. We are committed to making a transition to a clean energy future in a responsible manner, working closely with the affected communities to minimize impacts and help identify new opportunities. The proposals laid out above, and discussed in more depth by APS witness Lockwood, show this commitment.

VI. THE APPROPRIATENESS OF APS EXECUTIVE COMPENSATION

Q. PLEASE EXPLAIN WHY APS'S EXECUTIVE COMPENSATION LEVELS ARE APPROPRIATE.

A. APS's executive team is composed of highly qualified and experienced individuals. Their leadership guides the delivery of clean, reliable and affordable electric service to our customers and reflects responsible stewardship of both shareholder and customer dollars. APS serves 1.3 million customers in a complex operating and regulatory environment, which includes Palo Verde, the nation's largest nuclear power plant. Members of the APS executive team are not only important contributors to the success of the Company, they also offer valuable leadership and services to the communities where they live.

In order to attract and retain highly qualified executives, the Company must offer compensation and benefits that are competitive with other regulated and non-regulated companies. To ensure that its compensation is market-based and appropriate, APS relies upon an independent compensation consulting firm to annually review and evaluate executive compensation.

It is also important to understand that not all executive compensation is included in APS's rates. For example, stock-based compensation and supplemental executive retirement benefits (SERP) have historically been excluded from customer rates, and APS has removed them from Test Year expenses. Additionally, portions of APS's executive compensation are allocated to and paid by the various owners of the participant generating stations the Company operates. In short, I am confident that APS's compensation philosophy is prudent and that our executive team compensation is reasonable and appropriate.

VII. CONCLUSION

Q. DO YOU HAVE ANY CLOSING REMARKS?

A. APS has a strong history of innovation and leadership in the utility industry and in Arizona. Our record of providing safe, reliable, affordable, increasingly clean electricity, and supporting our communities goes back 130 years. This is made possible by the hard work of our employees, diligently meeting the needs of our customers, each and every day. It is also made possible through partnerships with interested stakeholders and requires continued responsible regulatory oversight and support. Our commitment to fulfilling our mission and achieving our vision of a clean energy future for Arizona has never been stronger.

Our Clean Energy Commitment and assistance for the Navajo Nation, Navajo County Communities, and the Hopi Tribe is consistent with our legacy of innovation and leadership. But this commitment will require collaboration from our employees, customers, stakeholders, and the Commission.

Integral to the success of these commitments is the financial stability of APS. Accordingly, I ask the Commission to carefully review the evidence in the record of this case and follow the established policies, rules, and legal requirements to allow the Company to recover its costs of service and earn a reasonable return on its investment.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

ATTACHMENT 2

REBUTTAL TESTIMONY OF BARBARA D. LOCKWOOD

On Behalf of Arizona Public Service Company

Docket No. E-01345A-19-0236

November 6, 2020

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**REBUTTAL TESTIMONY OF BARBARA D. LOCKWOOD
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-19-0236)**

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Barbara D. Lockwood. I am Senior Vice President of Public Policy at Arizona Public Service Company (APS or Company). In that role, I am responsible for regulatory matters before the Federal Energy Regulatory Commission (FERC) and the Arizona Corporation Commission (ACC or Commission), as well as government affairs at both the state and federal level, community affairs at the local level, corporate giving, and the Company's environmental, social and governance (ESG) policy. My business address is 400 N. 5th Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS MATTER?

A. Yes. I provided direct testimony in this case.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My Rebuttal Testimony presents the Company's revised revenue requirement request that reflects changes to the requested Return on Equity (ROE) and return on the Fair Value Increment (FVI), corrections to both operating income and rate base, and updates to post-Test Year plant (PTYP) to incorporate actual expenses. APS is also adopting several recommendations from Staff witness Ralph Smith's Direct Testimony, as well as AECC witness Kevin Higgins.

I will discuss certain revenue requirement disallowances recommended by Staff and other intervenors, and comment on the misconceptions that continue to persist regarding the Company's implementation of the rates and rate migration approved in the last APS rate case. I will also comment on the formula rate and performance-based ratemaking discussions included in the testimonies of Staff witness David Dismukes, RUCO witness Frank Radigan, Sierra Club witness Cheryl Roberto, and SWEEP and WRA witness Brendon Baatz.

I will discuss securitization, a remaining book value cost recovery method highlighted by Chairman Burns in his August 11, 2020 letter to the parties in this docket that, if properly structured, has the potential to limit the impact of unrecovered plant costs on both APS and its customers. In that regard, I expand on the coal community transition discussion included in the Rebuttal Testimony of APS witness Jeffrey Guldner and discuss the progress APS has made partnering with these communities in planning for the future once APS exits its ownership in coal-fired generation facilities.

Finally, I will provide an overview of APS's proposed enhanced reporting requirements on several performance metrics that are discussed by Staff, SWEEP and WRA and the Sierra Club.

II. <u>SUMMARY</u>

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. APS has reduced its overall revenue requirement request in this case to $169 million, a reduction of $15 million from that requested in its original Application. This base rate request continues to include both the Four Corners Selective Catalytic Reduction (SCR) equipment and the Ocotillo Modernization Project investments and deferrals as discussed in the Company's Direct Testimony. The revised request also includes an updated PTYP request with used and useful investments and the actual cost of those investments through June 30, 2020. Notably, this 12-month period is not contested by any party in this proceeding.

The revised request includes a reduction in the Company's requested ROE to 10.0% and a reduction in return on the FVI to 0.8%, mirroring the Company's currently-approved ROE and return on the FVI. This maintains APS's financial stability, while reducing the impact of an increase to customers. The ROE and return on the FVI recommendations by Staff and intervenors are unreasonably low and would jeopardize the Company's financial health to the detriment of its customers. Specifically, RUCO's arbitrary ROE penalty proposal is not supported by fact and must be rejected by the Commission.

My review of Staff and intervenor testimony shows that misconceptions remain about the Company's implementation of its most recent rate case decision. APS has acknowledged that its customer outreach could improve and has been actively working with stakeholders to revise and refine its customer communications as discussed by APS witness Monica Whiting in her Rebuttal Testimony. Contrary to some testimony filed in this case, however, APS is not overearning, nor is it "overcharging" its customers.

Since the Company filed its Direct Testimony in this case, APS announced its Clean Energy Commitment, described in more detail by APS witness Guldner in his Rebuttal Testimony. This commitment includes the Company's exit from all coal-fired generation by 2031. APS recognizes the impact that this transition will have on the communities surrounding the coal plants operating in and around Arizona, and is working closely with stakeholders and the affected communities to develop a responsible transition plan to minimize impacts and provide support to these communities.

In conjunction with its Clean Energy Commitment, the Company believes securitization is a viable tool that can, if implemented properly, reduce the rate impacts of transitioning to a clean energy future. In light of the potential benefits to both customers and utilities, APS intends to pursue the necessary legal structures required for successful securitization in Arizona and is looking forward to working with stakeholders and the Commission on this issue.

III. REVISED APS REVENUE REQUIREMENT REQUEST

Q. PLEASE SUMMARIZE THE COMPANY'S REVISED REVENUE REQUIREMENT REQUEST.

A. APS has reduced its revenue requirement request to approximately \$169 million, a reduction of approximately \$15 million from the Company's original request in its Application. The Company's revised revenue requirement request, and the resulting impact to customer bills, is shown in Table 1 at the end of this section. When including the effects of moving the Tax Expense Adjustment Mechanism (TEAM) adjustor credit and other adjustors into base rates, the Company's net revised base rate increase is \$41 million, or 1.2%. However, to accurately depict the impact of APS's proposals on customer bills, the effects of adjustment mechanisms must also be considered. The revised request will have an average bill impact for all customers of 5.1%. The average bill impact for residential customers is 4.99%.

The Company continues to propose the inclusion of 12 months of PTYP in revenue requirement as discussed in the Rebuttal Testimony of APS witnesses Elizabeth Blankenship and Jacob Tetlow, and has updated the amount of PTYP requested to reflect projects in service and investment as of June 30, 2020.

Q. WHAT CHANGES DID THE COMPANY MAKE IN ITS ROE AND RETURN ON FVI REQUEST?

A. In APS's initial Application in this case, the Company proposed a ROE of 10.15% and a return on the FVI of 1.0%. These proposals resulted in a 7.41% weighted average cost of capital (WACC) and a fair value rate of return (FVROR) of 5.62%.

After considering the Direct Testimony of intervenors, APS proposes to revise and reduce its request to a ROE of 10%, and a return on the FVI of 0.8%. These revised proposals mirror the Company's currently-approved ROE and return on FVI. These revisions result in a proposed WACC of 7.33% and a FVROR of 5.51%.

Q. WHY DID APS REDUCE ITS ROE AND RETURN ON FVI REQUEST?

A. APS understands that rate increases can be difficult for its customers, especially with the uncertainty that the ongoing COVID-19 pandemic continues to inflict on the state of Arizona. As part of its ongoing commitment to its customers, the Company continued to look for ways to reduce the impact of the rate increase request on its customers after its initial Application in this case was filed. After carefully reviewing the financial impacts, APS determined that a modest reduction in the ROE and return on the FVI from that originally requested by the Company would still allow APS to maintain its financial stability, while reducing the impact of the Company's request on its customers.

Additionally, APS witness Ann Bulkley performed an updated analysis of the appropriate cost of equity for APS that takes into consideration changes in the financial environment since Direct Testimony in this case was filed over a year ago. The updated analysis finds that APS's reduced ROE request of 10% is reasonable based on her updated calculations. Likewise, APS witness Bulkley performed an updated analysis of the return on the FVI and determines an appropriate risk-free rate in today's financial environment is 1.28%. Although APS's revised request for return on the FVI at 0.8% is significantly below the rate supported by APS witness Bulkley's analysis, APS believes that its revised request achieves an appropriate financial balance for APS and mitigates rate increase impacts to APS customers.

Q. DID YOU REVIEW THE ROE AND RETURN ON FVI RECOMMENDATIONS BY STAFF AND INTERVENORS?

A. Yes, I did. Recommendations from Staff and intervenors range from 8.74% to 9.75% for ROE, and from 0% to 1.0% for return on FVI. APS witness Bulkley will address each of these recommendations in her rebuttal testimony.

I will, however, briefly address the ROE recommendation of RUCO witness Jordy Fuentes. RUCO's recommended baseline ROE is the lowest of all intervenors at 8.94%, a recommendation that APS witness Bulkley finds is unreasonable for the reasons outlined in her Rebuttal Testimony. RUCO witness Fuentes then recommends an additional 20 basis-point reduction to this ROE to "send a message" to APS regarding a perceived lack of adequate customer service. However, the information RUCO witness Fuentes relies upon does not support the imposition of a penalty on the Company and, in fact, many of the documents and reports RUCO witness Fuentes cited contain erroneous and misleading information, as I will address later in my testimony.

For example, RUCO witness Fuentes fails to recognize that rate increases for all utilities under the Commission's jurisdiction have been portrayed by all parties (including the Commission itself) as class average annual increases for at least the last 50 years in Arizona. This fact is acknowledged by the Commission in Decision No. 77292 (July 19, 2019), and thus, APS's use of a class average annual increase percentage can in no fashion be categorized as a "failure."[1] Likewise, the information portrayed on the APS bill is a direct result of Commission rule requirements to include unbundled price and type of service information on customer bills.[2] The Company agrees that this detailed

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[1] Decision No. 77292 in Docket No. E-01345A-18-0002 (July 19, 2019).
[2] A.A.C. R14-2-210.

information, while transparent, could be difficult for the customer to understand. But including this information should not be attributed to an APS "failure."

These are two examples of the misrepresentations RUCO witness Fuentes relied on to support his arbitrary reduction in RUCO's recommended ROE for APS. The Commission must reject this inappropriate and factually-unsupported recommendation.

Q. WHAT OTHER CHANGES ARE INCLUDED IN APS'S REVISED REQUEST?

A. Additional changes to the Company's request include such items as:

- Changes to various rate base and income statement pro formas for corrections and adjustments identified in the discovery process and reasonable revisions due to updated information that was not available at the time the Company filed its original request, as discussed in detail in APS witnesses Blankenship's and -Leland Snook's Rebuttal Testimonies;
- Certain Staff and intervenor recommendations APS accepted, including Staff's recommended updated base fuel rate, as discussed in APS witness Snook's Rebuttal Testimony; and
- Changes to reflect updated PTYP investment, as noted earlier in my Rebuttal Testimony.

Q. PLEASE EXPLAIN THE COMPANY'S ADVANCED ENERGY MECHANISM (AEM) PROPOSAL.

A. APS is proposing a new adjustment mechanism that would recover capital carrying costs and expense associated with the clean energy investments necessary for a clean energy future. In addition, this adjustor could replace and combine the Company's current Demand-Side Management Adjustment Clause

(DSMAC), Renewable Energy Adjustor Charge (REAC) and Lost Fixed Cost Recovery (LFCR) adjustment mechanisms into one comprehensive mechanism, if desired by the Commission. This adjustment mechanism is introduced in APS witness Guldner's Rebuttal Testimony and discussed in more detail in APS witness Snook's Rebuttal Testimony. As shown in the table below, APS proposes to collect coal community transition funds, which are discussed in detail later in my testimony, through this adjustor.

Q. PLEASE SUMMARIZE THE COMPANY'S REBUTTAL REQUEST.

A. The result of the changes to the Company's revenue requirement request is captured below (numbers have been rounded for ease of presentation).

Table 1. APS Revised Revenue Requirement Request

Customer Bill Impact = Net Base Rate Increase + Net Adjustor Changes	Dollars	Bill Impact
Total Revenue Deficiency in APS's Application	184M	5.6%
Base Rate Changes		
Net adjustments	(28M)	-0.9%
TEAM	(119M)	-3.6%
All other adjustors	4M	0.1%
Rebuttal Net Base Rate Request	**41M**	**1.2%**
Adjustor Changes		
Removal of TEAM credit	119M	3.6%
Transfer to base rates of all other adjustors	(4M)	-0.1%
AEM	13M	0.4%
Net Adjustor Changes	**128M**	**3.9%**
Total Rebuttal Customer Bill Impact	**169M**	**5.1%**

IV. <u>STAFF AND INTERVENOR TESTIMONY REBUTTAL</u>

Q. DID YOU REVIEW STAFF AND INTERVENOR TESTIMONY?

A. Yes. The majority of rebuttal to Staff and intervenor testimony is addressed by other APS witnesses; however, I would like to discuss my impression of the overall testimony filed by Staff and intervenors in this case. I will also address three specific items: APS's limited-income programs, employee cash incentives, and the Four Corners SCRs. In addition, simply because I do not address a specific statement or recommendation by Staff or intervenors should not be construed as my acceptance of that statement or recommendation.

Q. WHAT ARE YOUR OVERALL OBSERVATIONS REGARDING STAFF AND INTERVENOR TESTIMONY IN THIS CASE?

A. I remain concerned about the number of misconceptions that continue to exist regarding the actions taken by APS to implement its suite of rate schedules approved by this Commission in Decision No. 76295 (August 18, 2017), the Company's 2016 Rate Case. Throughout the parties' testimonies, statements are made that are simply incorrect, and witnesses are drawing conclusions and making recommendations based on these false and misleading statements and data. This is particularly concerning since APS has repeatedly stated the factual steps taken by the Company to communicate with its customers and to complete the rate migration process required by Decision No. 76295 in Commission proceedings, responsive letters to Commissioners, and discussions at various open meetings over the last two years.

Specific rebuttal to the reports, "An Evaluation of Arizona Public Service Company's Customer Education Plan and Its Implementation" written by Barbara Alexander and "Rate Review and Customer Outreach Program Evaluation of Arizona Public Service Company" written by Overland Consulting, initiated by the Commission to review the Company's rate implementation and customer communications, are included in the Rebuttal Testimonies of APS witnesses

Snook and Whiting.[3] To ensure the record is clear, I address a few of the most egregious of the false statements below.

- **APS is not overearning.** The Company's current authorized return on equity is 10.0%. This is stated, without ambiguity, in Decision No. 76295. That return on equity, calculated on an annual basis, was approved by the Commission. APS has proven through multiple filings at this Commission, including the financial data submitted in this docket, that the Company's actual ACC-jurisdictional return on equity has not exceeded 10% since that Decision.

- **APS is not "overcharging" customers.** The rate levels determined to be just and reasonable in Decision No. 76295 have been accurately and appropriately implemented by APS. The Commission determined in Decision No. 77292 that there is no evidence that APS improperly implemented the suite of rate plans and charges approved by the Commission.[4]

- **APS did not inappropriately transition residential customers to demand rates.** The APS rate plan auto-migration process outlined in Decision No. 76295 required the Company to move customers to the rate structure that was "most like" that which the customer was already being served under. APS followed that process. If a customer had chosen a demand rate prior to Decision No. 76295, that customer was moved to a demand rate. Table 2 below shows this rate transition concept.

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[3] Barbara R. Alexander, An Evaluation of Arizona Public Service Company's Customer Education Plan and its Implementation, Docket Nos. E-01345A-19-0236 and E-01345A-19-0003 (May 19, 2020); Overland Consulting, Rate Review and Customer Outreach Program Evaluation of Arizona Public Service Company, Docket No. E-01345A-19-0003 (June 4, 2019).

[4] *See* Decision No. 77292 in Docket No. E-01345A-18-0002 (July 19, 2019), p. 88, Finding of Fact 108.

Table 2. APS Rate Plan Migration Process

Plan type	Current service plans		New service plans
Flat	Standard	→	Lite Choice Premier Choice Premier Choice Large
Time-of-Use	Time Advantage (9-9 or 12-7)	→	Saver Choice
Demand	Combined Advantage	→	Saver Choice Max

Customers who self-selected a new rate may have made a conscious choice during the transition period to move from a non-demand rate to a demand rate; however, at no time did APS automatically transition a customer from a flat energy-only rate or time-of-use energy-only rate to any demand rate. APS witness Jessica Hobbick addresses this misrepresentation and the Company's rate migration in more detail.

- **While improvements may be called for, APS's Customer Education and Outreach Plan (CEOP) did not fail.** The CEOP developed by APS, as required by Decision No. 76295, was an extension of ongoing education and outreach efforts the Company has engaged in for many years. The goal of the CEOP was to provide customers with information to prepare for the transition to new rate plans, highlighting customer options, and ways to maximize savings. APS met this goal by diligently executing its CEOP, providing customers with multiple forms of outreach over multiple channels as the plan outlined.

These misrepresentations have clouded the important issues that are addressed in the Company's rate case Application and created unnecessary roadblocks for APS, the Commission and all stakeholders in the process of making improvements and creating sound energy policies for the future.

A. *Limited-Income Programs*

Q. DOES APS AGREE WITH THE LIMITED-INCOME PROGRAM CHANGES PROPOSED BY INTERVENOR WILDFIRE?

A. APS agrees with Wildfire that it is the right time to expand the Company's Energy Support programs (E-3 and E-4) to allow customers with incomes up to 200% of the federal income poverty guidelines to participate. APS witnesses Whiting and Hobbick discuss this program expansion in more detail in their rebuttal testimonies. It is important to note that the purpose of this expansion is to encourage more customers to enroll in the programs, which will require more funding than previously estimated. Therefore, approval of the deferral accounting mechanism for Energy Support program funding as described by APS witness Hobbick in her direct and rebuttal testimonies is critical to allow APS to expand the programs to more customers in need.

I believe the adoption of Wildfire's expanded eligibility requirements and the Company's commitment in this case to double its annual Crisis Bill funding from $1.25 million to $2.5 million annually provides critical relief to those in its community with the greatest need and enhances the Company's already significant commitment to its limited-income customers and community assistance partners.

B. *Employee Cash Incentive*

Q. DO YOU AGREE WITH THE POSITIONS TAKEN BY STAFF, RUCO AND AECC THAT PORTIONS OF CASH INCENTIVE SHOULD BE DISALLOWED?

A. No. These parties claim that because a portion of the incentive is tied to the Company's earnings that those costs should not be included in rates. However, as discussed by APS witness Blankenship, the only way for nearly all APS employees to successfully contribute to this metric is to continue to find efficiencies and reduce costs. Those savings are then given back to customers through rates.

Moreover, I would challenge what appears to be a conclusion by these parties that a financially-healthy utility, able to provide earnings to investors, is in some way contrary to the interests of its customers. Customers benefit when APS can earn a reasonable return on its investment, as that is how the utility can continue to attract the capital investment necessary to provide electricity to its customers on reasonable terms. The suggestion that the interests of investors and customers are in conflict in this regard is false. Therefore, the basis for these positions on incentive compensation is flawed, and these recommendations should be rejected.

C. *Four Corners SCR Investment*

Q. DID PARTIES DISCUSS THE RECOVERY OF THE SCR INVESTMENT AT FOUR CORNERS?

A. Yes. Staff and AECC both supported the inclusion of the SCRs and the SCR deferral in rates.[5] RUCO's position is to not allow recovery "at this time."[6]

Q. PLEASE DESCRIBE RUCO'S CONCERN WITH INCLUDING THE SCR INVESTMENT IN RATES.

A. RUCO witness Radigan recognizes that the Company's investment in the SCRs was mandated by federal environment requirements, but questions how Four Corners fits with APS's new Clean Energy Commitment of being 100% carbon free by 2050, and more specifically, how the topics of securitization and remaining book value of the Plant will be addressed by the Company.

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[5] Both parties also propose possible alternative calculation recommendations for the deferral, which the Company does not support.

[6] RUCO Direct Testimony of Frank W. Radigan at 16 (Oct. 2, 2020).

Q. WILL YOU PLEASE RESPOND TO RUCO'S CONCERNS?

A. As discussed by APS witness Brad Albert in his Rebuttal Testimony, Four Corners is, and will continue to be, an essential part of APS's generation fleet for the needed capacity and reliability benefits it provides to its customers. The events of this past summer, the hottest summer on record in Arizona, show how valuable Four Corners is to APS customers and the overall APS system. The SCR investment also allowed the plant to remain open to serve APS's customers and provide meaningful economic benefits to the Navajo Nation and surrounding communities. This asset is used and undoubtedly useful and should be recovered through rates.

I discuss APS's position on securitization below in more depth, but the Company is committed to pursuing the idea. However, there are some very real hurdles to overcome, and securitization is not a viable option to implement today. However, providing those hurdles can be adequately addressed, securitization could prove to be a very useful tool to recover the remaining book value of fossil generating units as the Company, customers and the Commission move to collectively pursue a cleaner energy future for Arizona. Regarding RUCO's question about the remaining book value of the Four Corners Power Plant, APS recommends that for purposes of this case, APS continue to depreciate the asset to 2038, despite its planned closing by 2031. This prevents upward pressure on rates that would occur from the accelerated depreciation necessary to depreciate the asset only through 2031.

V. SECURITIZATION

Q. CHAIRMAN BURNS REQUESTED PARTIES IN THIS PROCEEDING DISCUSS POSSIBLE METHODS OF RECOVERY OF REMAINING BOOK VALUE UPON CLOSURE OF THE FOUR CORNERS POWER PLANT. HAS APS RESPONDED TO THIS REQUEST?

A. Yes. APS responded to Chairman Burns by letter filed in this docket on November 6, 2020. The Company's response addresses each of the scenarios requested and discusses the benefits and costs of each cost recovery method suggested in the Chairman's request. APS witness Albert will discuss portions of the APS analysis in his Rebuttal Testimony.

I will not repeat the results of the Company's analysis here. However, I will discuss the securitization method of recovering remaining asset book value for retiring plants, as highlighted by Chairman Burns and discussed by Sierra Club witness Roberto that has the potential—if structured properly—to limit the impact of these costs on both APS and customers.

Q. WHAT IS APS'S UNDERSTANDING OF SECURITIZATION AS A PUBLIC SERVICE COMPANY FINANCING TOOL?

A. Securitization is a utility financing tool that relies upon low-cost, asset-backed securities—in this case securities backed by a present-day property right in a defined pool of revenues to be paid by customers—to reduce the cost of a utility's financial obligations and ultimately benefit customers through lower rates.

Securitization can be used to recover, at a lower total cost to customers, the remaining book value associated with certain assets that are retiring. Any remaining book value associated with such an asset is removed from the utility's rate base, such that the utility is no longer receiving a return on the investment.

The utility is then compensated through the proceeds of low-cost securitized bonds, which are then paid separately from jurisdictional rates.

Q. WHAT ARE THE BENEFITS TO UTILITY CUSTOMERS OF SECURITIZATION?

A. By reducing the cost of financing past investments and unlocking present access to capital, the resulting transaction can produce significant customer savings, while also enabling near-term utility reinvestment of capital into clean technology generation resources.

Q. WHAT IS THE STRUCTURE OF A TYPICAL SECURITIZATION TRANSACTION?

A. Under a typical securitization transaction, a utility would permanently exclude from its rate base the unrecovered value of assets that are no longer in service. In exchange, the utility would receive the proceeds of one or more tranches of securitized debt issued by a legally separate and bankruptcy-remote special purpose entity (SPE) with those proceeds corresponding with the book value removed from rate base and any other authorized transition costs. The utility would transfer to the SPE a present property right in a defined stream of revenues sufficient to service that debt—typically called "Transition Charges"—that the utility would otherwise have been itself entitled to receive. The utility would also remove the securitized assets from rate base.

Although the SPE would be expected to enter into a servicing agreement with the utility to collect the Transition Charges, those revenues, and the right to them are no longer the property of the utility. The SPE would then pledge its property interest in those revenues as collateral for the bonds it issues and use the Transition Charges it recovers over time to pay the debt service. For this to occur, the state must authorize the creation and alienation of that property right and its recovery by the SPE—and, most importantly, pledge that the property right and the recovery of the Transition Charges will not be impaired. APS does not believe that the Commission has the authority to create this right, or to make a legally-enforceable pledge of non-impairment. These features of securitization must be established by the Arizona Legislature.

Q. CAN YOU PLEASE EXPLAIN AT A HIGH LEVEL ANY NECESSARY PREREQUISITES TO SECURITIZATION?

A. APS continues to assess how securitization could be accomplished in Arizona, given the complex array of legal, regulatory, and financing issues involved. As seen in other states that have pursued securitization, it is necessary to have not only Commission involvement and support, but also authorizing legislation. While certain intervenors have suggested that legislation might not be needed in Arizona, APS disagrees. Legislation is needed to make the securitized bonds marketable and allows obtainment of the low interest rates needed to reduce costs to the utility's customers. In addition, legislation is needed to create a property right in the stream of revenues that create the collateral for the bond (the securitized asset). State legislation is also needed to establish an irrevocable pledge that the state will not impair the securitization property or the SPE's right to collect those revenues through customer charges. Put simply, there is a lot of work to be done to create the necessary structures to enable securitization in Arizona.

Q. PLEASE EXPLAIN HOW A SECURITIZATION TRANSACTION LIKE THIS CAN PRODUCE BENEFITS FOR APS CUSTOMERS AS COMPARED TO TRADITIONAL COST-RECOVERY.

A. With respect to the unrecovered book value of assets no longer in service, securitization offers several potential advantages as compared to conventional utility cost recovery. In this respect, securitization can lower customer costs. The Transition Charges are based on the cost of SPE-issued debt, which would likely be less than a utility's regulated cost of capital—rather than the cost of equity and debt capital required to prudently operate a utility, the Transition Charges are based on the typically lower cost of debt insulated from cost recovery and business risk. Indeed, because the Transition Charges are defined in advance and subject to a strong non-impairment pledge, and because the debt is structured with multiple credit features to support repayment, securitized debt is typically very highly-rated and low-cost debt.

Q. WHAT BENEFITS CAN SECURITIZATION PROVIDE FOR PUBLIC SERVICE CORPORATIONS LIKE APS?

A. Securitization can provide a utility, like APS, with an upfront infusion of capital, which it can reinvest in clean electricity generation infrastructure. Thus, APS can simultaneously look to replace rate-base value lost as part of the securitization, while at the same time building clean generation in support of APS's Clean Energy Commitment and Commission carbon reduction standards. When combined with automatic mechanisms for contemporaneous regulatory recovery associated with the construction of replacement clean generation, APS can have the necessary regulatory certainty to efficiently and quickly convert securitization proceeds into clean energy resources for Arizona electricity customers.

Q. IN LIGHT OF THESE POTENTIAL ADVANTAGES, DOES APS SUPPORT SECURITIZATION AS A WAY TO SAVE CUSTOMERS MONEY?

A. Yes, within reason. The potential for securitization to produce meaningful customer savings, along with providing a mechanism for APS to increase its investments into clean generation technologies—and producing even greater environmental benefits for customers—APS believes securitization, when established and structured appropriately, can provide concrete public policy benefits for the state of Arizona. APS also believes that any consideration of a securitization platform for Arizona must be coupled with contemporaneous cost-recovery mechanisms—such as the Company's proposed AEM, for instance—that directly focuses utility securitization proceeds into clean energy generation investments. APS therefore intends to pursue the necessary legal structures required to facilitate successful securitization transactions in Arizona.

VI. COAL COMMUNITY TRANSITION

Q. DO YOU AGREE WITH INTERVENORS NAVAJO NATION AND CITIZEN GROUPS THAT ASSISTANCE TO COMMUNITIES IMPACTED BY APS'S PLANNED EXIT FROM COAL PLANT OPERATION IS NECESSARY?

A. Yes. The Company's Clean Energy Commitment announced earlier this year, and discussed in APS witness Guldner's Rebuttal Testimony, includes a complete APS exit from coal plant operations by 2031. APS recognizes that this plan will have an economic impact on local communities that have relied on the operation of the plants for employment, economic activity and tax revenues, and the Company is committed to assisting these communities in a transition away from reliance on coal plants. While Four Corners is still an important part of APS's generation fleet, APS has heard from the affected communities and values its long-standing relationship with them. Therefore, the Company agrees that now is the right time to begin the process of planning for the transition away from coal.

Q. WHAT COMPONENTS ARE INCLUDED IN THIS PLAN FOR FOUR CORNERS?

A. The Company has been a partner with the Navajo Nation and the surrounding communities since the beginning of coal plant operation and meets regularly with leaders on a wide variety of topics. Discussions have recently explored potential opportunities for assistance from APS and have resulted in an agreement on several of the transitional components suggested by the Navajo Nation and

Citizen Groups and the development of an overall plan for coal community transition. The foundation of the APS Coal Community Transition Plan is the cash payment of $100 million, at approximately S10 million per year over the next ten years, to the Navajo Nation as discussed by APS witness Guldner. As these funds are part of a transition to a clean energy future, APS is proposing to collect these funds from customers through the AEM described by APS witness Snook.

APS has also committed to fund the economic development efforts of an existing or future Navajo Nation economic development organization for a period of five years at $250,000 per year from shareholder funds, to begin two years prior to the Company's ceasing operations at Four Corners and continue for three years after.

To facilitate electrification of the Navajo Nation, a critical concern for the safety and well-being of the Nation's residents, APS is requesting approval from the Commission for a modification to APS's Service Schedule 3 that will allow distribution lines to be extended up to 2,000 feet within the Nation at no cost to Navajo Nation applicants within the Company's service territory. In addition, APS will conduct or pay for a census of unelectrified homes and businesses in the APS service territory within the Nation to be completed by the end of 2021. APS will also prepare an assessment of the effectiveness of the 2,000-foot proposed extension and submit that assessment to the Commission and the Nation. APS is proposing that additional electrification projects within the Nation will be pursued at a funding level of $10 million, with S5 million of that amount recovered through APS's proposed AEM and S5 million funded by shareholders.

To support transmission line development within the Navajo Nation, APS will also provide $2.5 million per year to the Navajo Nation from shareholder funds beginning from the time the Four Corners Power Plant closes (or 2032, whichever is earlier) through 2038.

In summary, APS is proposing a net total of $128.75 million of support be provided to the Navajo Nation from 2021 through 2038. Of that total, $23.75 million will be provided by shareholders.

APS also agrees with the Navajo Nation and Citizen Groups that a key component of this transition plan should be the encouragement of renewable energy resource development within the Navajo Nation.

Q. HOW WILL APS SUPPORT RENEWABLE ENERGY DEVELOPMENT WITHIN THE NAVAJO NATION?

A. APS has agreed to solicit a total of 600 MW of clean energy resources within the Navajo Nation or in communities surrounding the Navajo Nation through one or more Requests for Proposals (RFPs) as part of the Company's Clean Energy Commitment, subject to the approval of the Commission. It is anticipated that the initial RFP or set of RFPs will seek a minimum of 250 MW of renewable energy located on Navajo Nation land and will be issued within the next 24 months. Subsequent RFPs would seek an additional 350 MW of clean energy projects to be issued no later than 12 months after the closure of the Four Corners Power Plant, subject to the approval of the Commission.

Q. WOULD APS BE ABLE TO DIRECTLY ALLOCATE ANY OF ITS FERC JURISDICTIONAL TRANSMISSION LINE CAPACITY TO SUPPORT TRIBAL RENEWABLE ENERGY DEVELOPMENTS AS SUGGESTED BY CITIZEN GROUPS WITNESS HORSEHERDER?

A. No. A public service corporation that owns and operates FERC-regulated interstate transmission facilities, such as APS's 345 kV and 500 kV transmission facilities in the Four Corners area, is subject to strict non-discriminatory, open-access regulations. To provide transmission service to any entity, including the Navajo Nation, tribal-owned enterprises, or renewable energy projects located within the Nation, APS must provide such service pursuant to APS's FERC-regulated open access tariff. APS itself must also comply with the requirements of its FERC-regulated open access tariff in order to use any transmission service on its system. APS has a transmission service reservation for service on its system that allows it to deliver Four Corners power to its retail customers and has committed to the Navajo Nation to preserve that transmission service reservation to support the renewable commitments outlined above that serve APS retail customers.

Q. WILL APS BE ABLE TO TRANSFER WATER RIGHTS ASSOCIATED WITH THE FOUR CORNERS POWER PLANT TO THE NAVAJO NATION?

A. No. BHP, the original owner of the Navajo Mine, is the owner of the water rights associated with the Four Corners Power Plant and the Navajo Mine. APS is willing to help and assist the Navajo Nation in pursuing these rights by making appropriate introductions, providing background information and encouraging BHP to engage with the Navajo Nation on this issue.

Q. WILL APS SUPPORT THE NATION IN SEEKING ADDITIONAL FUNDS FOR COMMUNITY TRANSITION FUNDING?

A. Yes. APS will support the Nation and other coalitions in seeking other funding for assistance with community transition. APS also commits that it will support and encourage other Four Corners participants to make similar commitments of support. It should be clear that the commitments made in this testimony are on behalf of APS only.

Q. WOULD YOU LIKE TO COMMENT ON JOB RE-DEPLOYMENT RELATED TO THE CLOSURE OF THE PLANT?

A. Yes. APS commits to preparing job re-deployment offers with the APS organization to all APS employees at least six months prior to closure of the plant.

Q. WOULD YOU LIKE TO COMMENT ON PROPOSED TRANSITION COMMITMENTS WITH THE NAVAJO COUNTY COMMUNITIES AND THE HOPI TRIBE?

A. Yes. APS assessed these areas, based on the Company's agreement with Navajo Nation, and is proposing transition funding as well as other collaborative efforts. While the size of APS's impact at Four Corners is significantly larger, a thoughtful, purposeful transition out of coal includes the affected communities from the Cholla Power Plant and Navajo Generating Station.

Q. IS APS PROPOSING SIMILAR COST RECOVERY FOR THESE TRANSITION PLANS?

A. Yes. In regard to the Cholla Power Plant, APS is proposing $12 million to the Navajo County Communities, to be paid over five years_to assist in a transition, with S10.9 million of that amount recovered through APS's proposed AEM and $1.1 million funded by shareholders. APS will also provide job re-deployment offers within the APS organization to all APS employees at least six months prior to closure of Cholla. Navajo County Communities primarily include the Navajo County General Fund, Northland Pioneer College and Joseph City Unified School District.

With respect to the Hopi Tribe, APS is proposing $3.7 million to be paid over five years with $3.35 million recovered through APS's proposed AEM and $0.35 million funded by shareholders.

VII. FORMULA AND PERFORMANCE-BASED RATEMAKING

Q. DID APS RECOMMEND THE ADOPTION OF A FORMULA RATE IN THIS PROCEEDING?

A. No. In Direct Testimony, APS suggested that a formula rate plan could be an alternative to multiple adjustment mechanisms and could provide the same benefits. As discussed in APS witness Snook's Rebuttal Testimony, APS continues to believe that adjustment mechanisms offer important benefits to customers, the utility and the Commission, and is not recommending that they be replaced with a formula rate.

Q. DID STAFF OR INTERVENORS RECOMMEND FORMULA RATES?

A. No. There seems to be universal agreement that formula rates are not currently appropriate for APS. Several intervenors did, however, suggest that the Commission consider future development of performance-based ratemaking (PBR) as a method of reducing costs and maintaining appropriate service levels.

Q. PLEASE DESCRIBE PERFORMANCE-BASED RATEMAKING.

A. PBR, sometimes referred to as performance-based regulation, is a method of utility regulation that—at its extreme—would replace the traditional method of determining utility revenue based on the value of capital investment used to serve customers (the cost of service method) with one based on the performance of the utility in comparison to a set of key metrics.

When considering the implementation of a broad PBR plan, however, it is important to carefully consider the perverse incentives an improperly-designed PBR plan can place on the utility.

Q. WHAT DO YOU MEAN BY "PERVERSE INCENTIVE?"

A. A perverse incentive is one that could directly or indirectly encourage or pressure a utility or its employees to work towards the avoidance of short-term automatic economic penalties incorporated into a PBR plan at the expense of safe system operation or excellent customer service.

This result can be avoided by designing PBR plans that include, for example, incentives that provide opportunity for both penalties and rewards and recognition of the possibility of extraordinary events that would make achievement of an arbitrary target unlikely.

Q. DOES APS SUPPORT FURTHER DISCUSSIONS ON PBR?

A. Certainly. APS supports a dialogue with the Commission, stakeholders and other interested parties on the effectiveness and appropriateness of PBR for jurisdictional utilities in Arizona. I note that the Commission currently has a generic docket open on the role of performance incentive mechanisms in regulated investor-owned electric utility rate cases, and APS will fully participate in that docket and in any other Commission forum on PBR.[7]

VIII. RECOMMENDED REPORTING REQUIREMENTS

Q. DID YOU REVIEW THE VARIOUS REPORTING REQUIREMENTS RECOMMENDED BY INTERVENORS IN THIS CASE?

A. Yes, I did. Despite not pursuing a direct connection between specific Company performance metrics and financial implications, a wide range of reporting requirements were recommended by several intervenors, including outage and reliability data, customer service and satisfaction metrics, and rate plan adoption. The goal of this diverse and detailed reporting, as stated by most intervenors, was to provide the Commission and stakeholders with information that could be used to measure the Company's performance in key areas of safety, reliability and customer service.

[7] Docket No. E-00000A-20-0019.

Q. IS APS WILLING TO PROVIDE THIS INFORMATION TO THE COMMISSION?

A. APS understands that the Commission and stakeholders are interested in reviewing the Company's performance in certain areas and is open to providing regular reports to the Commission on a wide variety of statistics and metrics, including some of the information suggested by Staff and intervenors. Some of the recommended reporting information is already provided to the Commission in its otherwise required compliance reporting and some of the requested data APS simply does not have at this time.

However, APS has carefully reviewed and considered the recommendations of Staff and intervenors and is proposing reporting on a set of metrics that APS believes will provide an appropriate overview of the Company's performance in the areas of greatest interest: customer service and reliability.

Recommended customer service metrics, which are proposed to be delivered quarterly, include customer rate selection statistics, Customer Care Center performance, and customer satisfaction criteria as measured by J.D. Power's nationally-recognized customer satisfaction survey. These metrics are discussed in more detail by APS witness Whiting.

Likewise, recommended reliability reporting statistics include overall distribution system performance, as well as performance by geographical region, reliability maintenance program discussions, and fire mitigation impacts on reliability statistics. These metrics would be reported on an annual basis and are described in detail in APS witness Tetlow's Rebuttal Testimony.

IX. CONCLUSION

Q. DO YOU HAVE ANY CLOSING REMARKS?

A. Yes. The revised revenue requirement request discussed in my Rebuttal Testimony demonstrates that APS has made significant movement to reduce the impact of its rate request to customers while still maintaining the Company's financial integrity and providing benefits over a wide range of stakeholder interests. This overall request is necessary to fulfill APS's commitment to its customers to provide reliable, clean and affordable energy today and into the future. Implementing the APS Clean Energy Commitment will require APS, its customers, the Commission, and stakeholders to all work together to achieve a sustainable energy future for its communities and the state of Arizona. My colleagues and I are looking forward to fulfilling this commitment.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

ATTACHMENT 3

REBUTTAL TESTIMONY OF BRAD J. ALBERT

On Behalf of Arizona Public Service Company

Docket No. E-01345A-19-0236

November 6, 2020

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REBUTTAL TESTIMONY OF BRAD J. ALBERT
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-19-0236)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Brad Albert. I am the Vice President of Resource Management at Arizona Public Service Company (APS or Company). My business address is 400 North 5th Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS MATTER?

A. Yes, I presented Direct Testimony in this case.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I respond to issues raised in the filed testimony of intervenors in this case related to my Direct Testimony. While I may not address every detail related to intervenors' recommendations, it should not be interpreted that I agree with each position unless specifically stated within my testimony. I also respond to the resource planning aspects of questions raised by Chairman Burns in his letters dated August 11 and September 1, 2020 related to Four Corners retirement scenarios.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Citizen Groups and Sierra Club make a number of comments and recommendations on the on-going operation of Four Corners. I address the flaws in their analysis, the biggest of which is a failure to adequately address system reliability. Additionally, lessons learned from the heat storm of this last summer further discredit the analysis behind their recommendations. Some of those same lessons can be used to show what is meant by resource adequacy, and why the current AG-X program, while in compliance with all the rules for the program, does not provide it.

APS has analyzed different Four Corners scenarios in its recent Integrated Resource Plans (IRPs), and most recently in a response letter to Chairman Burns. I will discuss the relevant portions of that letter and how it can shed additional light when discussing the future of the plant.

APS's time-of-use (TOU) hours of 3 p.m. to 8 p.m. window are appropriate. That window is supported by APS's load shape now and provides the correct price signal to defer or eliminate the needs for some investments in the future.

Later in my testimony, data will show that the solar market in APS's service territory remains robust under the resource comparison proxy (RCP) construct. For that reason, and to continue the Commission's decision to decrease the cost shift to non-solar customers over time, the Company maintains its original proposal to keep the annual RCP step-downs.

I also defend APS's avoided cost calculation for rooftop solar exports but agree with Staff witness Phillip Metzger that it is not necessary for the Commission to make a decision on that in this rate case.

Lastly, I briefly discuss the Ocotillo Modernization Project (OMP), including the integral role it played in reliability this last summer.

III. FOUR CORNERS RETIREMENT

A. *Intervenor Analysis*

Q. DID ANY OF THE INTERVENORS FILE TESTIMONY RELATING TO FOUR CORNERS RETIREMENT?

A. Yes. Citizen Groups witnesses Mike Eisenfeld and David Schlissel, and Sierra Club witness Tyler Comings filed testimony addressing the potential retirement of Four Corners.

Q. GENERALLY, WHAT IS THE POSITION OF THESE INTERVENORS REGARDING FOUR CORNERS?

A. In general, the Sierra Club and Citizen Groups assert that Four Corners should or will be retired earlier than currently planned and they assert that lower cost generation alternatives are available. Specifically, Sierra Club witness Comings recommends retiring Four Corners as soon as possible, or at least by 2023. He does not recommend disallowing any past costs at Four Corners, with the exception of costs that have been incurred and that would be needed to operate the plant past 2023.

Citizen Groups witnesses Eisenfeld and Schlissel posit that Four Corners is likely to retire before 2031 and assert that there are lower cost resource alternatives available.

Q. DO YOU AGREE WITH SIERRA CLUB AND CITIZEN GROUPS' ASSERTIONS AROUND THE POTENTIAL RETIREMENT OF FOUR CORNERS?

A. No. Their analyses ignore the realities of operating a reliable power system and use unrealistic or improper assumptions that lead to inaccurate conclusions. Most of the analyses found in these intervenors' testimonies focus on future plant operations and as such have little relevance to this rate case, however, the intervenors attempt to cast doubt on the economics and reliability of Four Corners and so I will discuss their analyses in more detail below.

Q. WHAT IS THE BIGGEST ISSUE WITH THE INTERVENORS ANALYSIS?

A. Their analyses do not adequately address system reliability. APS is responsible for operating an intentionally diverse portfolio of resources and interacting with the market on a minute by minute basis to reliably meet customers' demand. It takes careful planning and a deep understanding of the system and resource capabilities to maintain high reliability. However, the intervenors' studies simply assume reliability with no evidence to support it.

Q. WHAT IS THE LIKELIHOOD THAT APS COULD CONTRACT FOR EXISTING GENERATING ASSETS TO MEET PEAK LOAD REQUIREMENTS IN THE NEXT FEW YEARS?

A. I have little confidence that APS would be able to contract for reliable generating assets in the future. Over the past decade, thousands of MW of generation have been removed from the western market, either through retirement or utility purchase of the once large supply of merchant generation. Generation retirements for example include Four Corners Units 1-3, Cholla 2, Navajo Plant, and San Juan Units 2 and 3. California has retired San Onofre Nuclear Generating Station (SONGS) and many natural gas once through cooling units. More retirements are anticipated in the next few years including Cholla 4 by the end of this year, followed by San Juan 1 and 4 in 2022, and Cholla 1 and 3 in 2025. The market is too tight to assume that it can provide for the reliable replacement of Four Corners 4 and 5 if they were to retire early.

Q. FIRST LET'S DISCUSS SIERRA CLUB WITNESS COMINGS' AND CITIZEN GROUPS WITNESS SCHLISSEL'S PROPOSALS TO REPLACE FOUR CORNERS WITH MARKET PURCHASES. ARE YOU OPPOSED TO RELYING ON THE MARKET FOR LOW COST POWER?

A. No, APS continually interacts with the market to reduce fuel and purchase power costs for customers by allowing us to reduce production from the Company's resources at times when wholesale market purchases are available at prices below APS's cost to produce. APS is opposed, however, to relying on non-asset backed market purchases to meet fundamental reliability requirements in tight market conditions like the western grid is experiencing today and is likely to experience in the future. Market purchases like the ones used in the intervenors' cost comparisons run the risk of being cut when the non-asset backed power is not available. This was one of the issues that played a role in the rolling blackouts this summer in California.

Q. WHAT ROLE DOES THE MARKET PLAY IN THE RELIABILITY OF APS'S SYSTEM?

A. APS uses asset-backed resources available in the market to help meet reliability needs such as merchant generators that can dedicate their output or sell to APS under a tolling agreement. The Company minimizes the use of market purchases such as those available in the forward market at Palo Verde when the market is short. It is also important to note that capacity from the Energy Imbalance Market (EIM) cannot be used to meet the Company's reliability requirements. Under EIM rules, APS is required to go into each hour with balanced schedules and not rely on the market to meet resource adequacy requirements.

Q. DOES THE WESTERN WHOLESALE MARKET IN WHICH APS OPERATES PAY FOR RELIABILITY?

A. No. The kind of reliability benefits like resource adequacy that are provided by Four Corners and many other units are not reflected in the wholesale market prices. The western wholesale market prices are indicative of power that can be purchased (or sold) without the backing of a specific generating resource. It is not designed to support profitability of regional power plants, and the market price is largely driven by the variable costs of the units on the margin hour by hour. In part, one of the reasons the wholesale market prices are as low as they are, is precisely due to plants like Four Corners that operate day in and day out.

Q. IF RELIABILITY IS NOT EXPLICITLY PURCHASED FROM THE MARKET, IS A COMPARISON OF REPLACING FOUR CORNERS WITH MARKET PRICES USEFUL?

A. No. This analysis fails because if every plant that could potentially have saved money by being removed from the market was in fact removed from the market, there would not be enough capacity left to reliably meet customer demand during high usage periods. In addition, as described more below, the western market is already capacity short as demonstrated by the rolling blackouts this summer, and there are more planned power plant retirements in the future, so the market cannot be counted upon to meet future reliability needs. I categorically reject that Four Corners could simply be replaced with market purchases as it does not present a viable or comparable alternative to maintain a safe, reliable system for APS's customers.

Q. NOW LET'S DISCUSS MR. EISENFELD CLAIMS THAT APS COULD SAVE MONEY BY RETIRING FOUR CORNERS IN 2023 AND REPLACING IT WITH SOLAR PLUS STORAGE AND WHOLESALE MARKET PURCHASES. FIRST OFF, IS APS OPPOSED TO SIGNIFICANTLY INCREASING RENEWABLE ENERGY AND STORAGE ON YOUR SYSTEM?

A. Not at all, in fact just the opposite is true. In January of this year, APS announced its Clean Energy Commitment that entails adding significant amounts of renewable generation, energy storage and ending coal generation by 2031. APS's plan is to do this in a way that is clean, affordable and reliable for customers.

APS's 2020 IRP, which reflects the Clean Plan Commitment, has nearly 2,000 MW of new utility scale renewables, plus 1,250 MW of battery energy storage by 2025. If Four Corners were to retire before 2031, APS's share of Four Corners would likely need to be replaced by more than 1,000 MW of additional renewable generation plus 1,400 MW of battery energy storage on top of what is reflected in the IRP.

Q. PLEASE EXPLAIN WHY YOU DISAGREE WITH CITIZEN GROUPS WITNESS EISENFELD'S CONTENTIONS?

Based on the current limited experience with energy storage and affordability concerns (APS and industry-wide), adding Four Corners replacement on top of current plans in the near future is too costly and risky. Based on the immaturity of the technology and the limited amount of experience the utility industry has to date, the amount of energy storage suggested by Citizen Groups witness Eisenfeld is too much too soon and presents a substantial reliability risk to customers.

Q. DO YOU AGREE WITH THE LEVELIZED PRICES CITIZEN GROUPS WITNESS EISENFELD USED FOR THIS ANALYSIS?

A. No. Neither the wholesale market, nor renewable generation plus storage provide the same reliability service as Four Corners, so using a levelized cost comparison is inappropriate and does not provide meaningful information that could be used in a decision-making process. Citizen Groups witness Eisenfeld bases his analysis on replacement resources taken in isolation that cannot be scaled to replace Four Corners on APS's system. It is well-accepted that the capacity value of solar generation decreases as penetration of the resource increases on a given system. The same is true for energy storage systems. This means it takes far more solar plus storage than Citizen Groups witness Eisenfeld assumes to replace Four Corners. Therefore, even if it was not too risky, the levelized price he uses is understated.

Q. WHAT OTHER CONCERNS DO YOU HAVE WITH CITIZEN GROUPS WITNESS EISENFELD'S ANALYSIS?

A. Citizen Groups is basing its claim on a study prepared by Strategen for the Sierra Club. There are several major flaws in the analysis.

- As stated above, Strategen fails to adequately consider APS system reliability and understates both the amount of energy storage that would be required to replace Four Corners (due to the capacity value of solar generation and energy storage decreasing as penetration of the resource increases on a given system), and the relatively limited operating experience in utility service that the industry has at this time with grid-scale battery storage systems.

- The Strategen study uses public cost information from a single proposed solar plus storage project facility that would not apply to APS. It is based on a small solar plus 3-½ hour duration energy storage facility that is the second phase of a project. Some of the project costs of the second phase were included with the first phase, artificially lowering the cost of the second phase.[1] It underestimates the amount of energy storage required to provide the same reliability that Four Corners delivers, and therefore significantly underestimates the cost of that alternative.

- Strategen assumes a 30 percent Investment Tax Credit (ITC) that would not likely be available for the replacement project, therefore understating the cost of the alternative.

- Strategen's results appear to be based on a base case retirement of Four Corners in 2038 instead of 2031. Although correct at the time they performed the study, that assumption is outdated and overstates the cost of operating Four Corners.

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[1] *See* Comments by Arizona Electric Power Cooperative Inc., (AEPCO) in response to The Arizona Coal Plant Valuation Study by Sierra Club and Strategen Consulting, pg. 5, Docket No. E-00000V-19-0034 (Dec. 31, 2019).

- The savings reported by Strategen reflect the entire plant, not APS's 63 percent ownership share, and inflates their estimate.

Q. ARE THERE LESSONS TO BE LEARNED FROM THE ROLLING BLACKOUTS IN CALIFORNIA ON AUGUST 14TH AND 15TH?

A. Yes. California has been aggressive in its transition to clean energy and has incorporated large amounts of renewables into its system while retiring thermal assets, and relying on imported power from neighboring regions. The events of August 14^{th} and 15^{th} were a result of their planning processes not keeping pace with those changes, resulting in unintended consequences. This should not hinder APS's commitment to a clean energy future but indicates the Company needs to carefully plan for it.

Q. HAVE THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR (CAISO) AND THE CALIFORNIA ENERGY COMMISSION (CEC) DETERMINED THE EXACT CAUSES OF THE ROLLING BLACKOUTS?

A. CAISO and the CEC issued a Preliminary Root Cause Analysis of the Mid-August Heat Storm on October 6, 2020. Their analysis identified three high level causes.

1) The climate change-induced extreme heat storm across the western United States resulted in the demand for electricity exceeding the existing electricity resource planning targets. The existing resource planning processes are not designed to fully address an extreme heat storm like the one experienced in mid-August.

2) In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to lead to sufficient resources that can be relied upon to meet demand in the early evening hours. This makes balancing demand and supply more challenging. These challenges were amplified by the extreme heat storm.

3) Some practices in the day-ahead energy market exacerbated the supply challenges under highly stressed conditions.

Q. WHAT IS THE RELEVANCE OF ANY OF THOSE CAUSES TO THE FOUR CORNERS REPLACEMENT STUDIES?

A. The first cause reflects that there were not enough imports available from other regions due to the heat storm. Based on this, it is confirmed that there are not surplus generation resources available in the regional wholesale market during peak customer usage periods to provide the kind of reliability customers expect from APS. It is inappropriate to assume that the market can provide resources, particularly during peak hours and/or days, as was assumed by Citizen Groups witness Schlissel.

The second cause shows that APS needs to make sure that planning targets keep up with the Company's clean energy transition. APS needs to be intentional and careful in the way it integrates large amounts of renewables and storage technologies. APS has an aggressive plan, and significantly adding to it by replacing a large resource such as Four Corners too early could have serious reliability implications.

Q. WAS APS ABLE TO MEET ITS CUSTOMER LOADS DURING THE AUGUST 14TH AND 15TH HEAT STORM WITHOUT INTERRUPTIONS?

A. Yes, APS was able to meet its customers' loads on those days. Although, in an abundance of caution, APS asked customers to conserve, and customers responded to the call for voluntary conservation.

Q. WHAT ROLE DID MARKET PURCHASES PLAY FOR APS ON THOSE DAYS?

A. APS had a small amount of market purchases from CAISO that were curtailed. Fortunately, and due to sound resource planning in Arizona, the Company was able to replace them with APS resources and avoid curtailments for customers.

Q. WHAT ROLE DID FOUR CORNERS UNITS 4 AND 5 PLAY ON THOSE DAYS?

A. Four Corners Units 4 and 5 performed very well this summer and were operating at essentially full power over the late afternoon and evening hours on those two days, providing significant reliability benefits to the system and to customers. As I will discuss later in my testimony, the OMP also played a critical role this summer.

Q. IF FOUR CORNERS HAD ALREADY BEEN RETIRED AS SUGGESTED BY INTERVENOR WITNESSES, WHAT ROLE WOULD THE MARKET HAVE PLAYED IN SERVING YOUR CUSTOMERS' LOADS?

A. It is difficult to say because I cannot retrospectively tell you what resources APS would have procured to replace Four Corners. But I can say that if APS did not construct new resources, retiring Four Corners Units 4 and 5 would have removed over 1,500 MW from the western market, causing a resource-constrained market to be even more resource-constrained and potentially leading to rolling blackouts in Arizona, or more extensive rolling blackouts in California.

Q. SIERRA CLUB WITNESS COMINGS COMPARES THE PROJECTED LEVELIZED COSTS OF OPERATING FOUR CORNERS WITH GENERIC PURCHASES. HE CONCLUDES APS COULD SAVE MONEY. DO YOU AGREE?

A. No. Once again, the witness fails to account for APS's fundamental obligation to operate the system reliably. In order to replicate the reliability provided by Four

Corners, the Company would need to significantly increase the amount of renewables plus storage. This would increase costs beyond those projected by Sierra Club. Even assuming, for arguments sake that Sierra Club's proposed plan is cheaper than operating Four Corners, the plan is not workable. For the reasons explained above, generic market purchases are not sufficient to replace Four Corners. I have also discussed the pace of renewables plus storage that would be required for APS to attempt to replace Four Corners with new assets on top of the aggressive plan already in place. Sierra Club's analysis does not hold up when taken in the context of the scale required and APS system dynamics. It should be entirely disregarded.

B. *APS's Analysis*

Q. HAS APS EVALUATED AN EARLY RETIREMENT OF FOUR CORNERS?

A. Yes, in its 2017 IRP, APS evaluated a carbon reduction portfolio that assumed Four Corners retirement in 2031 rather than 2038, the original retirement date. In addition, APS recently evaluated retiring the plant prior to 2031 in response to Chairman Burns' request.

Q. WHAT DID THE RESULTS IN THE 2017 IRP INDICATE ABOUT THE RETIREMENT DATE?

A. The analysis indicated a slight increased cost in the 15-year term if Four Corners were retired in 2031 rather than 2038, and a slight savings in the long term (30 years). These results did not provide a compelling economic reason to advance the retirement date at that time. Sierra Club witness Comings alleges APS ignored those results. However, in the IRP it was noted, "[s]hould circumstances significantly change over the course of the Planning Period, the Selected Plan may be modified to better fit the conditions prevalent at the time such a decision is made.

APS will monitor key variables such as carbon legislation and gas prices which influence the economics and will continue to evaluate its options."[2]

Q. HAS APS EVALUATED RETIRING FOUR CORNERS PRIOR TO 2031?

A. APS recently evaluated retiring Four Corners before 2031 in response to questions from Chairman Burns. Until now, however, APS did not evaluate alternatives that retire Four Corners prior to 2031 for several reasons. Four Corners is jointly owned by APS and four other entities, and together the owners have a coal contract that runs through 2031. It is not an option for APS to retire the plant without the agreement of the other owners. Furthermore, community impacts of retiring the plant are significant and must be carefully considered even before such evaluations could be made, as described by APS witness Barbara D. Lockwood in her Rebuttal Testimony.

Q. PLEASE SUMMARIZE CHAIRMAN BURNS' REQUEST.

A. Chairman Burns asked APS to analyze the rate impacts to customers using four different cost recovery methods for a number of different Four Corners retirement dates. The first method was to use accelerated depreciation through the planned retirement dates. The other three were to recover remaining book value using securitization at an APS assumed interest rate, and securitization at plus and minus one percent of the APS's assumed interest rate. He additionally requested that APS analyze the rate impacts using the four different cost recovery methods for Cholla Units 1 and 3 retirement date of 2023.[3]

Q. WHAT PARTS OF THE RESPONSE ARE YOU ADDRESSING?

A. In my testimony, I address the resource planning impacts including Four Corners replacement assets such as renewables plus storage, and the long-term economics

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[2] APS's 2017 IRP at 138.

[3] The Cholla analysis is addressed in the response to the Chairman's letter, not in this testimony.

of those alternatives. APS witness Lockwood is addressing the securitization policy issues in her Rebuttal Testimony.

Q. HOW DID YOU ANALYZE THESE ALTERNATIVES?

A. APS retained an outside consulting firm, Energy and Environmental Economics Consulting (E3), to evaluate these alternatives using high level modeling based on information provided in APS's 2020 IRP. E3 previously worked with APS and a stakeholder group to model various issues in preparation for the latest IRP filing in June of this year.

Q. WHAT ARE THE KEY ISSUES RELATED TO RETIREMENT OF FOUR CORNERS?

A. The most important issues from a modeling perspective are (1) ensuring that the replacement resources can provide a high level of reliability so that customers summertime peak loads are met, and (2) maintaining affordable electric service for customers.

The high-level modeling performed for this analysis is not meant to provide precise answers – it is intended to be more directional in nature and be responsive to Chairman Burns' request.

Q. HOW DID E3 ASSUME THAT LOST FOUR CORNERS GENERATION WOULD BE REPLACED?

A. Four Corners could potentially be replaced in a variety of ways, and E3 assumed it would be replaced by 600 MW of solar plus storage, 800 MW of storage, and 450 MW of wind. It is important to note that due to the high penetration of renewables and storage expected to be on APS's system as a result of the Clean Energy Commitment, it takes a total of 1,400 MW of storage (600 MW stand alone, and 800 MW combined with solar PV) and 750 MW of renewables in the mix to provide the same approximate on-peak value of APS's 970 MW share of Four Corners. The recent occurrences in California demonstrate that the market is no longer in a surplus capacity position and should not be relied upon for these capacity needs. Therefore, the assumption was made that new resources would need to be built to replace the peak capacity contribution of Four Corners.

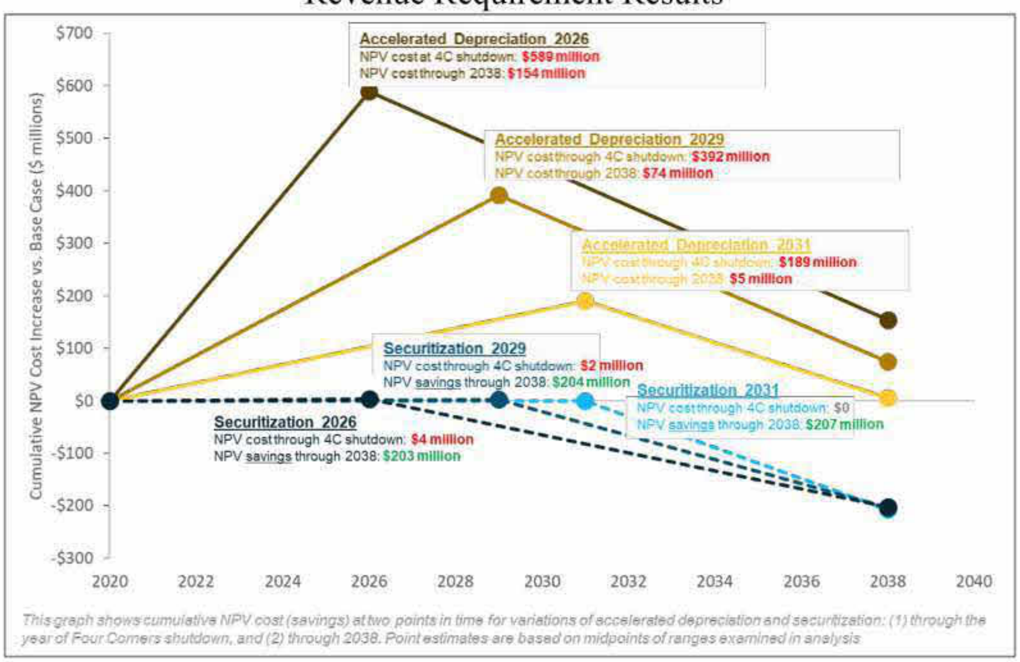
Q. WHAT COST ASSUMPTIONS WERE USED FOR THE FOUR CORNERS REPLACEMENT TECHNOLOGIES?

A. For the analysis discussed in my testimony, E3 used the resource cost assumptions from APS's 2020 IRP.

Q. PLEASE SUMMARIZE THE RESULTS OF THE ANALYSIS.

A. Figure 1 below summarizes the analysis and cost impacts of accelerated depreciation and securitization on Four Corners shutdown years of 2026, 2029, and 2031, and are based on the midpoint of the range of interest rates analyzed in the response to Commissioner Burns.[4] Numbers are in millions of dollars over an 18-year period and are shown as differences in revenue requirement from a Base Case (e.g. the APS-filed "Accelerate" case from the 2020 IRP).

Figure 1 – Summary of Net Preserve Present Value (NPV)
Revenue Requirement Results



[4] As discussed in my testimony in response to intervenors a 2023 shutdown is not possible given the timeframe does not allow adequate time to procure and assure replacement resources required to maintain reliable operations, and therefore has not been modeled.

Q. WHAT ARE YOUR CONCLUSIONS FROM THESE RESULTS?

A. This figure illustrates two key findings: 1) accelerated depreciation would increase customer costs for a transition from coal to clean generation, regardless of retirement date; and 2) the modeling demonstrates potential savings in all securitization scenarios. It is important to again note that the important operational and reliability considerations associated with an early shutdown are not reflected here and must be considered to determine the appropriate path forward.

Q. WHAT IMPORTANT OPERATIONAL AND RELIABILITY CONSIDERATIONS ASSOCIATED WITH AN EARLY SHUT DOWN NEED TO BE CONSIDERED?

A. The three most important considerations are that 1) battery energy storage technology is relatively new and has limited experience, 2) APS already has aggressive clean energy plans including significant amounts of renewables and energy storage, and adding to those plans significantly increases the risk of reliance on a relatively immature technology, and 3) the wholesale market cannot be relied upon to provide the high level of reliability APS and customers expect.

Q. DO YOU BELIEVE THAT THE RETIREMENT DATES FOR THE SCENARIOS IN THE ANALYSIS ABOVE PRESENT VIABLE OPTIONS?

A. I have concerns about the viability of retiring Four Corners in 2026. Four Corners represents a sizable contributor to APS system reliability, and APS as well as the industry are still learning how to integrate battery energy storage systems into resource portfolios. Total U.S utility scale battery energy storage installations from 2012 through 2019 amounted to only 1,104 MW/1,703 MWh,[5] equating to an average duration of 1.5 hours. In comparison, E3 assumed it would take 1,400

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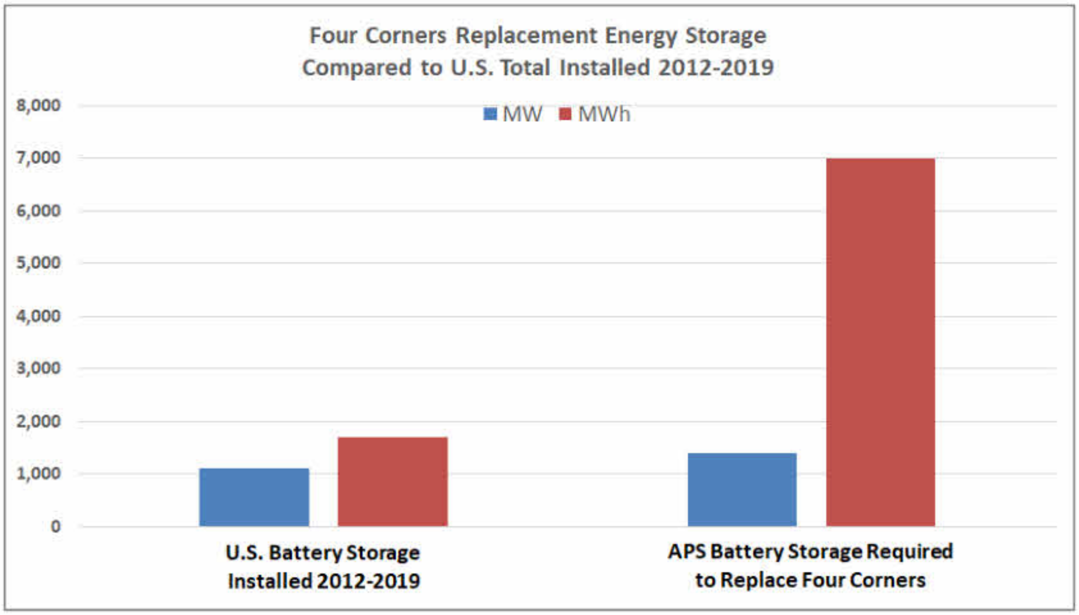
[5] *Energy Storage Monitor*, Wood Mackenzie Power & Renewables/U.S. Energy Storage Association, September 2020.

MW/7,000 MWh of storage (5-hour duration) to replace Four Corners, more than the entire U.S. industry installed through 2019 as indicated in Figure 2 below.

Figure 2 – Four Corners Replacement Energy Storage
Compared to U.S. Total

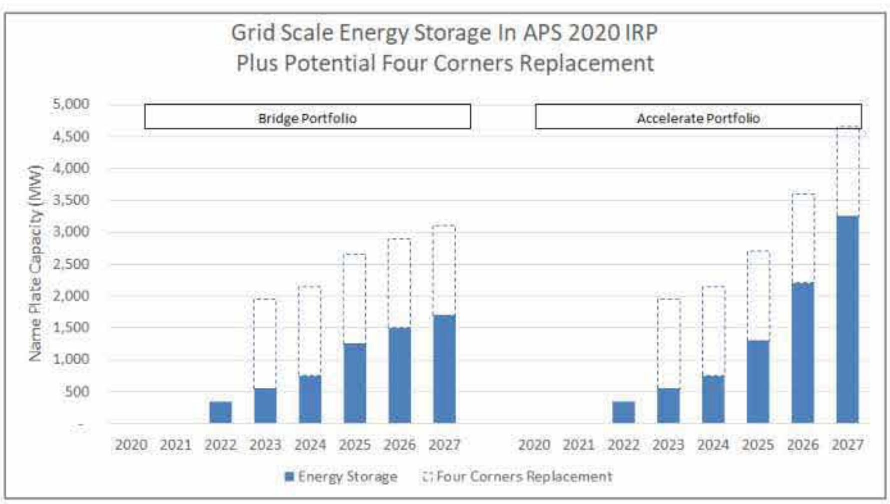


APS believes the pace of renewable and energy storage systems represented in the 2020 IRP between now and 2025 is appropriate. Beyond 2025, the pace of additions depends on a number of factors, including commercial demonstration, adoption of safety standards and affordability to customers. Replacing Four Corners with renewables and storage by 2026 would increase planned energy storage additions by about 63-93 percent. This represents a significant increase in risk of reliance on battery storage technology as compared to the base case.

Q. APS'S 2020 IRP INCLUDES THREE PORTFOLIOS DESIGNED TO MEET ITS CLEAN ENERGY COMMITMENT. PLEASE DESCRIBE THESE PORTFOLIOS AND THEIR RELEVANCE TO THE TIMING OF FOUR CORNERS PLANNED RETIREMENT.

A. The portfolios set out three possible paths for APS to follow as the Company pursues the Clean Energy Commitment. They are nearly the same for the first five years as APS takes significant steps towards a clean energy future. After 2025, they diverge in terms of how quickly APS adopts renewable plus storage technologies. The Bridge Portfolio (Bridge) is moderately aggressive in its deployment of renewables plus energy storage, and the Accelerate Portfolio (Accelerate) is the most aggressive of the three plans. The IRP also includes the Shift Portfolio (Shift) which is in between Bridge and Accelerate. For the purposes of putting the amount of new resources required to replace Four Corners in perspective, my testimony only discusses Bridge and Accelerate. In all of the 2020 IRP portfolios, Four Corners retires in 2031. APS has not chosen which path to follow at this time, and the path that the Company ultimately follows will depend on energy storage technology development, technology costs and customer affordability. Advancing the retirement of Four Corners would significantly increase the adoption of new technology beyond what APS already considers aggressive implementation of renewables plus storage in those plans. Whether or not that could be done reliably and cost effectively remains to be seen and should not be decided today. Figure 3 below illustrates the levels of new utility scale battery energy storage systems represented in the two bookend portfolios. Potential Four Corners replacement capacity is indicated by the dotted lines.

Figure 3 – New Utility Scale Battery Storage in APS 2020 IRP



As can be seen from the chart, adding Four Corners replacement on top of the clean energy plans would represent a very quick and very large increase in new technology on the system, and bring more technology risk than is appropriate at this time.

C. *Reliability of the Four Corners power plant*

Q. DO ANY OF THE WITNESSES IN THIS DOCKET CRITICIZE THE OPERATIONAL CAPABILITY OF THE PLANT?

A. Yes. Vote Solar witness Ronny Sandoval and Citizen Groups witnesses Eisenfeld and Schlissel claim that Four Corners is becoming increasingly unreliable and is likely to continue that trend as the plant ages.

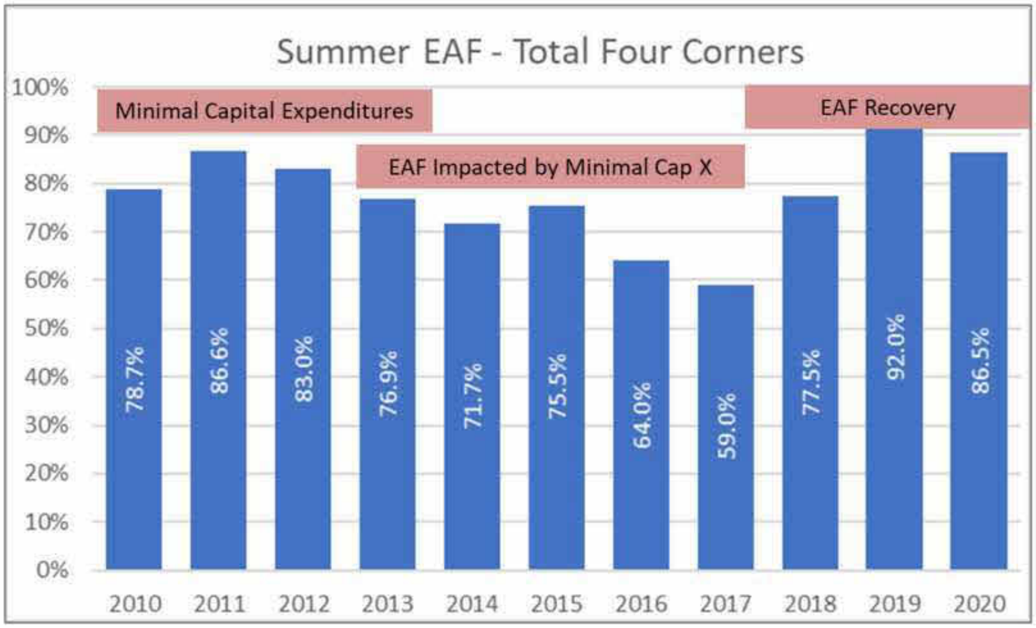
Q. WHAT METRICS DO YOU USE TO QUANTIFY RELIABILITY?

A. Equivalent Availability Factor (EAF) is a key indicator of the reliability of a generating unit used in the utility industry. EAF reflects the equivalent amount of time a unit is capable of running at full output, factoring in scheduled maintenance, forced outages and unit derates. APS closely monitors EAFs and an important subset of that – the summertime EAF. The summertime EAF is important because overall system reliability is driven by the high summertime loads.

Q. DO YOU AGREE WITH THE CRITICISMS FROM CERTAIN INTERVENORS REGARDING THE RELIABILITY OF FOUR CORNERS?

A. No. There was a period in the mid-2010s, however, where Four Corners exhibited lower EAFs than other times before or since due to low capital investment related to a period of uncertainty regarding the future of the plant. Since that time, the Company has increased its investment in capital improvements. Accordingly, the EAF has been much improved over the past three years.

Figure 4 - Four Corners Summertime Equivalent Availability Factor



Q. CITIZEN GROUPS WITNESS SCHLISSEL POINTS TO 2020 AS AN UNRELIABLE YEAR BASED ON THE FIRST SIX MONTHS OF OPERATION. IS THAT AN ACCURATE ASSESSMENT?

A. No. Citizen Groups witness Schlissel appears to misinterpret the data. Both units were taken out of service for scheduled maintenance activities in the spring of 2020. Unit 5 was out of service for more than two months for a scheduled outage. Quoting the EAF or capacity factors for the first six months, especially in a year such as this, is misleading. As seen in Figure 4 above, Four Corners performed very well in the summers of 2019 and 2020 and was an essential component in the Company's ability to meet its customers' service needs.

Q. DO YOU EXPECT FOUR CORNERS TO BECOME UNRELIABLE AS THE PLANT AGES?

A. I anticipate that the plant will be maintained in a manner to provide reliable service to APS customers and the customers of the other owners. As the plant gets closer to retirement and replacement resources are phased in, it is possible that the summertime EAFs could decrease in the plant's last few years of service as capital spending is reduced prior to its scheduled retirement.

Q. CITIZEN GROUPS WITNESS SCHLISSEL RECOMMENDS THAT APS BEAR THE RISK OF FOUR CORNERS OPERATING DIFFERENT THAN WHAT IS MODELED IN THE COMPANY'S 2020 IRP. IS THAT APPROPRIATE?

A. No. It is inappropriate to use long-term resource planning information in setting rates. Information used in planning models such as the ones used in APS's IRP is generally not the same thing as information used to set rates. When looking out 15 years from a planning perspective, the IRP captures things at a high level, certainly not at the accounting level used in setting rates.

IV. <u>ON-PEAK TIME-OF-USE WINDOW FOR RESIDENTIAL RATES</u>

Q. WHY IS IT IMPORTANT TO HAVE TIME DIFFERENTIATED RATES, AND WHAT IS APS'S CURRENT ON-PEAK TIME-OF-USE (TOU) WINDOW?

A. The need for new resource capacity is driven by a limited number of high load hours during the summer. APS's on-peak rates are intended to incent customers to shift their usage during these high load hours to lower load hours, thereby saving all customers money by deferring the need for new resources needed to serve peak load in the future. APS's current on-peak time-of-use window is from 3 p.m. to 8 p.m. weekdays.

Q. HOW WAS THAT WINDOW DETERMINED?

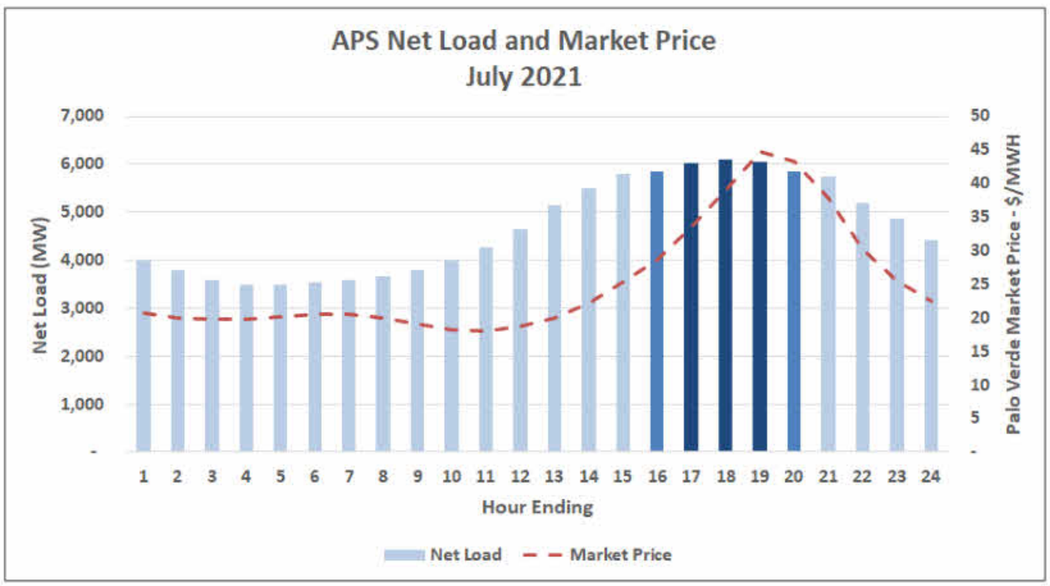
A. Determination of the on-peak TOU window is a balance between customer convenience and hourly system load and market prices. I address the load shape and market price impacts while APS witness Jessica Hobbick addresses customer impacts.

In the 2016 rate case, APS demonstrated that from a system load perspective, the on-peak window for residential rates should be from 3 p.m. to 9 p.m. weekdays, but those hours were shortened to 3 p.m. to 8 p.m. to provide more evening off-peak hours to customers and to acknowledge customer convenience.

Q. HAVE YOU UPDATED YOUR ANALYSIS?

A. Yes. Figure 5 below shows the Company's projected net load curve for an average day in July of 2021 as well as the projected wholesale market prices. An average day in August looks very similar.

Figure 5 - APS Net Load Curve and Wholesale Market Prices – July 2021



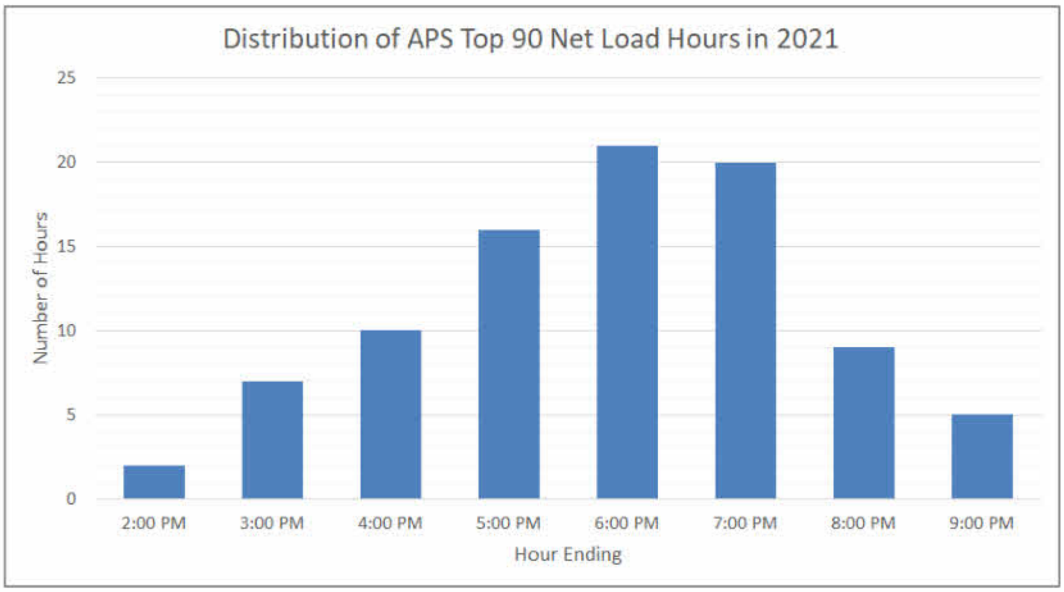
Q. WHAT HOURS ARE MOST IMPORTANT FROM A RESOURCE ADEQUACY AND RELIABILITY PERSPECTIVE?

A. APS has found that most of the Company's reliability needs are driven by the 90 highest net load hours in a given year, and APS typically uses a top 90 hours load analysis to determine the on-peak capacity value of variable resources such as solar and wind.

Q. WHEN DO THESE TOP 90 HOURS OCCUR?

A. Based on APS's 2021 net load curve, all 90 hours fall in the summer between hours ending 2 p.m. and 9 p.m. Recognizing that is too wide of a time period for customers, this data still supports an on-peak window from 3 p.m. to 8 p.m., encompassing 84 percent of APS's top 90 hours, as indicated in Figure 6 below.

Figure 6 – Distribution of APS Top 90 Load Hours in 2021



Q. IF THE PURPOSE OF TOU RATES IS TO DEFER FUTURE INVESTMENT, IS IT APPROPRIATE TO LOOK AT RESOURCE NEEDS IN FUTURE YEARS WHEN SETTING TOU HOURS?

A. Yes. APS load shape has changed over the past few years and is expected to continue to change into the future. Basing TOU hours on outdated, annual averaged load shape information does not send the right pricing signals to customers.

Q. WHAT IS YOUR RESPONSE TO SWEEP AND WRA WITNESS BRENDON BAATZ'S CRITICISM OF APS'S USE OF FUTURE YEARS LOAD FORECASTS TO ASSESS TOU HOURS?

A. As mentioned above the benefit of TOU hours is to send a correct price signal to help defer or reduce peaking investment needed over time. Even if the forecasted magnitude were to be off, APS's forecasted hours of peak would not be, and that is the driver for the hours. However, the values presented in my current testimony are based on a forecast year of 2021, which should alleviate SWEEP and WRA witness Baatz's concern.

Q. WHAT WOULD BE THE IMPACT OF REDUCING YOUR ON-PEAK TOU WINDOW TO 4:00 P.M. TO 7:00 P.M. AS SUGGESTED BY STAFF WITNESS DAVID DISMUKES AND SWEEP AND WRA WITNESS BAATZ?

A. Only 63 percent of the Company's top 90 hours occur inside that three-hour window. That means that there is still a significant amount of reliability considerations outside of that window. Net loads are still very high from 3 p.m. to 4 p.m. and from 7 p.m. to 8 p.m., and it is still important for APS to manage loads in those periods to defer new resources in the future and save infrastructure costs for all customers. APS witness Hobbick discusses how customers respond to the current TOU periods, and I am concerned that if the window was shortened, customer loads in the hours from 3 p.m. to 4 p.m. and in the hours from 7 p.m. to 8 p.m. would be higher than those reflected in the analysis. This would further reduce the number of hours in those windows to well under 63 percent of the top 90 hours. That does not align top reliability hours with rates, nor send the intended price signals to encourage thoughtful energy use by customers during peak hours. Furthermore, in the future as more customers shift their loads by doing such things as installing programmable thermostats and charging electric vehicles, it is likely that they will lower their thermostats and start charging in the first off-peak hour, further increasing the load at that time. If that hour starts at 7 p.m., that could create new peaks and not allow for the long-term infrastructure savings intended by TOU pricing.

Q. EVEN WITHOUT A CHANGE TO TOU HOURS, IS APS'S LOAD SHIFTING LATER IN THE DAY?

A. Yes. Historically, APS's annual peak load has occurred at hours ending 4 p.m., 5 p.m. and 6 p.m. The last time the peak load occurred at 4 p.m. was 2006. In three of the last five years, the peak occurred at 6 p.m. As customers have continued to add rooftop solar, the peak has shifted later in the day, and APS expects that trend to continue due to the continuing additions of rooftop solar to the system. Additionally, when considering the effect of grid scale renewable, the net peak can be shifted even later in the day. For example, on the peak day of 2020, the Company's instantaneous net peak load occurred at 6:24 p.m., 45 minutes later than the system peak load.

Q. IS THERE STILL ANOTHER WAY TO EXPLAIN WHY A SHIFT TO AN EARLIER TOU WINDOW IS NOT SUPPORTED BY DATA?

A. Yes, from a wholesale market price perspective, it does not make sense to shave off the 7 p.m. to 8 p.m. hour from the current on-peak TOU period. As indicated in Figure 5 above, wholesale market prices are highest in the 6 p.m. to 7 p.m. hour (hour 19), and second highest in the in the 7 p.m. to 8 p.m. hour (hour 20). Removing 7 p.m. to 8 p.m. from APS on-peak TOU period would be misaligned with wholesale market prices. Retaining that hour in the peak period not only helps save infrastructure in the long term, but also provides immediate benefits to customers by reducing on-peak purchase power costs.

Q. DO YOU HAVE ANY COMMENTS ON STAFF WITNESS DISMUKES' ANALYSIS THAT HE CONTENDS SUPPORTS SHORTENING THE ON-PEAK TOU WINDOW?

A. There are at least three serious shortcomings with his analysis: (1) using annual average load shapes, (2) using a sub-set of APS customers, and (3) using only customer load, not system load. Similarly flawed, SWEEP and WRA witness Baatz analysis sufferers from two of the three issues below as well.

A. *Using average load shapes*

Q. HOW DOES STAFF WITNESS DISMUKES ANALYZE APS PEAK HOURS?

A. Staff witness Dismukes creates the average hourly load for three historical years (2016, 2017, 2018) for hours ending one through 24 for APS non-solar residential customers, to determine what APS TOU peak hours should be.

Q. IS THIS AN APPROPRIATE METHOD FOR DETERMINING THE PEAK WINDOW?

A. No, it is not. Since resource needs are driven by the summer period, the analysis should be based on the summer period load shapes, not annual average. Using loads outside of the summer have little impact on system reliability and future resource additions. TOU pricing is meant to reduce future investment in new infrastructure, which is driven by system net loads in the summer including solar customers. Staff witness Dismukes is completely missing the drivers of new investment in infrastructure.

B. *Using subset of customer loads*

Q. IS THERE AN ISSUE WHEN THE ANALYSIS ONLY CONSIDERS A SUBSET OF APS CUSTOMERS' LOAD?

A. Yes. Staff witness Dismukes analysis uses only APS non-solar residential customers. APS's resource needs are driven by the entire system, not just a subset of the system.

Q. WHY DOES THIS PARTICULAR SHORT-COMING OF THE ANALYSIS MATTER?

A. The growing amount of distributed solar generation on the system is impacting load shapes and will impact it more in the future. Additional solar will make the ramping periods steeper, and therefore ignoring solar customers' usage patterns does not lead to a complete or meaningful answer.

C. *Not using system loads*

Q. WHAT IS THE ISSUE WITH ONLY USING CUSTOMER LOAD INSTEAD OF SYSTEM LOAD?

A. Similar to the point above, APS has a significant amount of renewable resources on the system and will continue to add more. The generation from these resources drops off late in the afternoon and this has a significant impact on future resource needs. Ignoring the impact of renewables on the system leads to a suboptimal result.

V. AG-X AND RESOURCE ADEQUACY

Q. WHAT PART OF CALPINE AND DIRECT ENERGY WITNESS GREG BASS' TESTIMONY ARE YOU ADDRESSING?

A. Calpine and Direct Energy witness Bass contends that the market purchases used to serve AG-X customers' load provide resource adequacy. I discuss resource adequacy and show that his understanding is not in line with industry standards. AG-X rate implications are addressed by APS witness Leland Snook.

Q. PLEASE DEFINE RESOURCE ADEQUACY.

A. North American Electric Reliability Corporation (NERC) defines resource adequacy as the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses). The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecasted peak demand.

Q. WHAT IS A WESTERN SYSTEMS POWER POOL (WSPP) SCHEDULE C PURCHASE?

A. Service Schedule C details the terms for firm sales or exchange service. A stipulated damages provision applies to failure to deliver or receive power. Firm service may be curtailed within mutually agreed to recall times, due to force majeure, or to meet public utility or statutory obligations. In the latter case, if the seller interrupts, it will pay damages consistent with the terms of the WSPP Agreement. While Schedule C refers to firm service, it is important to note that it is financially firm for the buyer, not firm in the sense of physical delivery.

Q. IS A SCHEDULE C PURCHASE SERVED FROM A SPECIFIED UNIT?

A. No, the seller does not have to designate a specific generating source in order to commit to a WSPP Schedule C sale. The seller could rely on their ability to purchase available generation in the spot market (day-ahead or real-time) in order to find a specific generating source to fulfill the obligations of the sale. This reliance on spot market purchases will not work when there are no remaining generation sources available for purchase in the wholesale market. Therefore, when the market cannot provide, these purchases/sales are subject to curtailment.

Q. HOW DO AG-X CUSTOMERS SERVE THEIR LOAD?

A. Primarily with WSPP Schedule C purchases.

Q. CALPINE AND DIRECT ENERGY WITNESS BASS ALLEGES THAT DURING ITS TOP 100 LOAD HOURS IN 2017, APS ITSELF RELIED SUBSTANTIALLY ON THESE SAME FIRM WSPP SCHEDULE C CONTRACTS TO SERVE ITS OWN LOAD. DOES APS RELY ON THOSE CONTRACTS TO PROVIDE RESOURCE ADEQUACY?

A. No. While APS did use these contracts to serve customer load, the Company did not rely on them for resource adequacy purposes. These purchases were made in the economic interest of serving customers at the lowest cost. With the exception of AG-X, APS did not show them on the resource plan, did not rely on them for reliability purposes and do not include them in meeting the reserve margin obligations. Had these purchases become unavailable or curtailed, APS had generation assets or asset backed purchases backing them up.

Q. PLEASE EXPLAIN WHAT HAPPENED WITH AG-X CUSTOMERS AS WELL AS YOUR OWN WSPP SCHEDULE C PURCHASES ON AUGUST 18, 2020.

A. On August 18, 2020, CAISO curtailed imports into the APS balancing area from AG-X suppliers and certain irrigation district suppliers, which the Company was relying on to serve system load. These imports were supplied from short-term market purchases which were not backed by firm supplies from a designated power plant, a capacity contract, or reserves. Therefore, neither of these groups provided sufficient resource adequacy to serve their loads. In fact, in hour ending 18, almost 60 percent of the AG-X scheduled energy was curtailed. However, the loads of AG-X customers or irrigation district customers were not curtailed to reflect the curtailment of generation provided by their generation service providers, and therefore APS made up for the generation with its own reserves.

In contrast, while APS also experienced a curtailment of CAISO imports designated for its retail load during this time, the Company was not relying solely on these short-term market purchases to be able to serve its retail load. In addition to its previously procured portfolio of firm resources such as its existing generating assets and asset-backed purchases which provided a 15 percent reserve margin, APS also procured day-ahead purchases to better prepare the Company to respond to potential contingency events, should they occur on August 18th. These firm resources allowed APS to replace the curtailed CAISO purchases with its reserve power without impacting reliability.

Q. DOES SHOWING AG-X CAPACITY ON YOUR RESOURCE PLAN MEAN APS ACCEPTS IT AS PROVIDING RESOURCE ADEQUACY?

A. No. Especially given the recent experiences with the August heat storm, APS plans to re-assess how the Company reflects these types of purchases in the IRP.

VI. <u>SOLAR ISSUES – AVOIDED COST METHODOLOGY AND RCP</u>

Q. DID YOU PROPOSE A METHODOLOGY TO CALCULATE THE AVOIDED COST OF RESIDENTIAL SOLAR EXPORTS IN YOUR DIRECT TESTIMONY?

A. Yes. In my Direct Testimony, I proposed a methodology for calculating the avoided cost of residential solar export energy. Decision No. 75859 (January 3, 2017) stipulated that the RCP methodology be initially used to set the rate to be paid to residential rooftop solar customers for energy exported to the grid. It also ordered the development of an avoided cost methodology with five-year forecasting, within a time frame that will allow its implementation to occur no later than December 31, 2019.[6] Once the five-year avoided cost methodology is finalized, the Commission will have the flexibility to utilize either the avoided cost methodology or RCP methodology (or a combination of both) in setting a formula for the DG export rate in subsequently filed electric utility rate cases for use in annual updates to the export rate.

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[6] This has since been revised to December 31, 2020. *See* Decision No. 77654 dated June 30, 2020.

Q. DID YOU RECOMMEND THAT YOUR PROPOSED METHODOLOGY BE USED TO ESTABLISH THE VALUE AT THIS TIME?

A. No. I recommended the continued use of the Commission-approved RCP methodology to determine the value at this time.

Q. HAVE ANY OF THE PARTIES TO THIS CASE COMMENTED ON YOUR AVOIDED COST METHODOLOGY TESTIMONY IN THEIR FILED TESTIMONY?

A. Yes. This topic was addressed by Staff witness Metzger, Vote Solar witness Sandoval, and SEIA witness Kevin Lucas.

Q. DID STAFF HAVE ANY RECOMMENDATIONS ON THE METHODOLOGY?

A. Staff witness Metzger recommends not addressing the avoided cost methodology as part of this case because the methodology has far-reaching impacts for customers across Arizona and is best addressed in a separate docket that already exists.

Q. DO YOU SUPPORT STAFF'S RECOMMENDATION?

A. Yes, I do. Because the Company is currently compensating residential rooftop solar exports based on Staff's RCP methodology, it is not necessary for the Commission to approve the Avoided Cost Methodology in this rate case.

Q. WHAT ARE VOTE SOLAR WITNESS SANDOVAL'S RECOMMENDATIONS?

A. Vote Solar witness Sandoval recommends that the Commission should reject the Company's methodology because it omits several value categories. He contends that APS has omitted certain value streams from the Avoided Cost Methodology and has assumed the values are zero because they are difficult to quantify. He makes another recommendation that I will discuss later.

Q. DO YOU AGREE WITH VOTE SOLAR'S CONCERNS OVER THE COMPANY'S METHODLOGY?

A. No. The Company analyzed each potential value stream and made a determination of whether or how to value it based on the facts and circumstances. In some cases, the values actually were zero. In other cases, APS determined it was inappropriate to assign a value, for example where the costs were highly speculative.

Q. WHAT CATEGORIES DID YOU ANALYZE AND FIND TO HAVE ZERO VALUE?

A. APS assigned zero value to avoided transmission and distribution costs. During peak load hours, solar customers use almost all of their solar energy to meet their own energy requirements, and export very little to the grid. Since little is exported at these times, the export energy does not line up well with peak loads and has limited ability if any to defer transmission and distribution costs. The Company's 2019 BTA documented that no transmission could be avoided due to rooftop solar exports, and the Company could not find any distribution upgrades that could be avoided by the presence of rooftop solar exports. APS left placeholders in the methodology for those items in case they become non-zero in the future.

Q. DOES VOTE SOLAR WITNESS SANDOVAL MAKE ANY RECOMMENDATIONS RELATED TO THE COMPANY'S CAPACITY AND ENERGY LOSS CALCULATIONS?

A. Yes. Vote Solar witness Sandoval states that the Company is unclear in its explanation of distribution loss values and recommends that the Company should be required to conduct load flow and other appropriate studies to quantify the expected loss reduction impact of Distributed Energy Resources (DERs).

Q. DO YOU AGREE WITH HIS RECOMMENDATION?

A. No. The loss values in the proposed methodology are appropriate and are based on demand and energy loss studies filed in APS rate cases. His recommendation to conduct load flow studies is not practical since load flow studies are performed for a single hour only. Furthermore, APS does not model down to the level of individual customers, so this recommendation would not produce the result intended by Vote Solar witness Sandoval.

Q. VOTE SOLAR WITNESS SANDOVAL CLAIMS THAT "CARBON," "RESILIENCE" AND "MARKET PRICE RESPONSE" SHOULD BE INCLUDED IN THE AVOIDED COST. DO YOU AGREE THEY SHOULD BE INCLUDED?

A. No. To the extent that carbon is an actual cost to customers (such as a carbon tax), it would already be factored into the avoided energy cost. To the extent he is referring to a "societal cost" of carbon, it should be omitted. Societal costs, or externalities, may sometimes be used in the resource selection process, but once the resource selection is made, customers are only asked to pay for the actual cost of the resource itself.

Market price response and resilience are highly speculative categories of costs that could apply to other resources, but because they are speculative have not and should not be used to calculate avoided costs for any resource. Just because there may be theoretical ways of calculating such benefits does not mean that they should be used in ratemaking. These fall into the same area discussed in the Value of Solar Order where it states,

> Staff believes that economic benefits should be considered qualitatively only and opposes any adders for them. Staff states that such costs and benefits are very difficult to quantify, are not included in the ratemaking formula for existing generation and other facilities, and are not unique or incremental to DG.[7]

[7] Decision No. 75859 at 110 (Jan. 3, 2017).

Q. WHAT WAS SEIA WITNESS LUCAS' RECOMMENDATIONS ON CONTINUED USE OF THE RCP?

A. SEIA witness Lucas recommended freezing the RCP stepdown at the 2019 Tranche level and extending the duration of the RCP price lock to 18 years.

Q. WHAT WAS THE INTENT OF THE COMMISSION IN ESTABLISHING THE RCP AND AVOIDED COST METHODOLOGY?

A. Decision No. 75859, Finding of Fact No. 133 states, "[t]here is a need for a valuation of DG methodology that will provide a gradual transition away from the current net metering model for compensating DG exports, toward compensation of DG exports that reflects the actual value of DG."

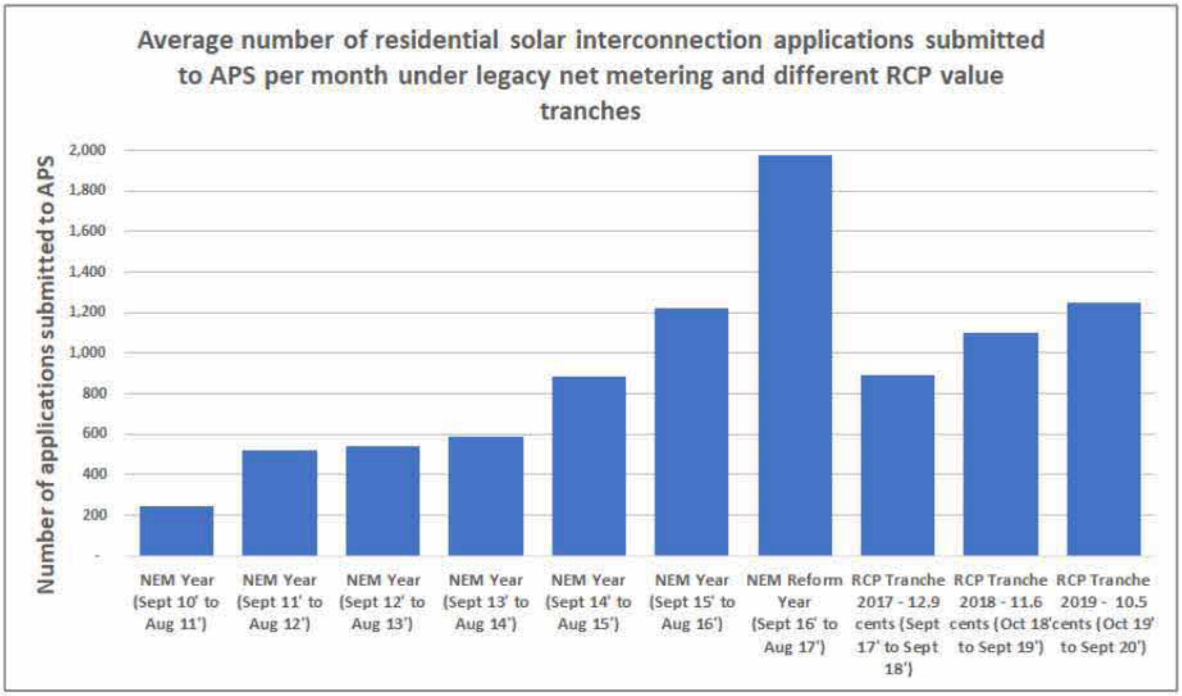
Q. DOES FREEZING THE RCP EXPORT RATE AT CURRENT VALUES ACCOMPLISH THAT PURPOSE?

A. No. The purpose in moving from values established in the RCP to avoided cost is to eventually eliminate the cost shift from rooftop solar customers to non-solar customers. Freezing the rate and extending it from ten to 18 years as proposed perpetuates and increases the cost shift.

Q. DO YOU AGREE WITH SEIA WITNESS LUCAS'S ASSERTION THAT THE ARIZONA SOLAR MARKET HAS EXPERIENCED A NOTABLE SLOWDOWN IN GROWTH SINCE THE PRE-RCP PERIOD?

A. No. The solar market in APS's service territory has remained healthy following the transition to the RCP tariff. Figure 7 (using the same Arizona Goes Solar data cited by SEIA witness Lucas) shows that the solar industry in APS's service territory pulled significant demand forward before the net metering grandfathering deadline, causing a temporary spike in application numbers from September 2016 to August 2017 (represented in the chart as the Net Energy Metering (NEM) reform year). After the transition to the RCP tariff, the market saw a temporary slight slowdown in the numbers of applications submitted to APS, as solar companies worked to install the pipeline of grandfathered projects that had built-up during the NEM reform year. After that brief slowdown, the number of applications rebounded under the RCP tariff to equal the number of applications submitted under net metering.

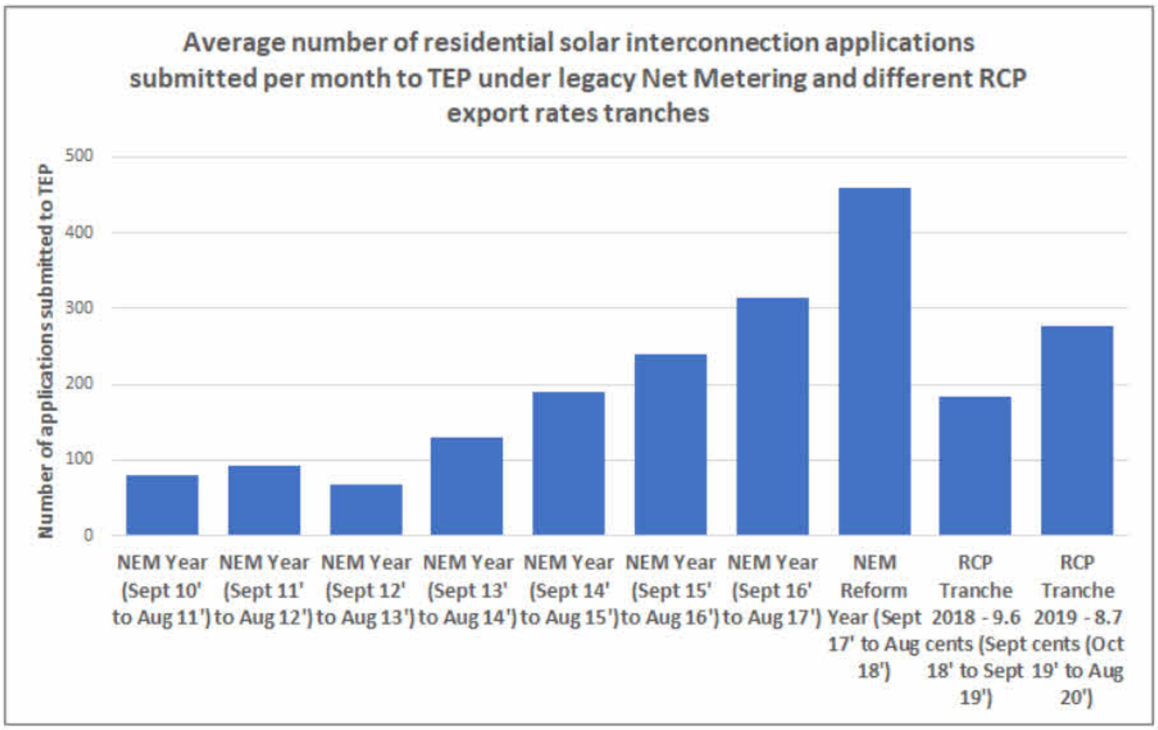
Figure 7 – Residential Solar Interconnection Applications Submitted to APS



Q. DO YOU AGREE WITH SEIA WITNESS LUCAS'S CONCERNS ABOUT SOLAR APPLICATIONS AND INSTALLATIONS IN TEP'S SERVICE TERRITORY AND THAT THEY SHOULD INFORM DECISIONS REGARDING APS'S SERVICE TERRITORY?

A. No. As shown in the Figure 7 above, the solar market in APS's service territory has adapted well to the gradual declines in the RCP and a decline in the federal investment tax credit (which stepped down from 30 percent to 26 percent in 2020). In regards to the alleged downswing in applications and installations in TEP service territory, the Arizona Goes Solar data indicates that the solar market in TEP's service territory remains strong following the transition to the RCP tariff and a step down in the RCP value. Figure 8 below shows that the solar market in TEP's service territory experienced the same temporary spike in applications in the year leading up to the transition from NEM to the RCP tariff (shown as the NEM reform year), followed by a short-term slowdown, and then a rebound in applications numbers. Similar to the solar market in APS's service territory, the TEP solar market saw an increase in applications after the drop in the RCP value from Tranche 2018 (9.6 cents/kWh) to Tranche 2019 (8.7 cents/kWh).

Figure 8 - Residential Solar Interconnection Applications Submitted to TEP



Q. HAVE THE SHIFTS FROM NET METERING TO THE RCP TARIFF AND THE FOLLOWING STEP DOWNS IN THE RCP VALUE CAUSED THE SOLAR MARKETS IN APS OR TEP SERVICE TERRITORY TO FALL BEHIND THE TOP SOLAR UTILITIES IN THE WEST?

A. No. The solar markets in APS and TEP service territories remain national leaders following the shift to the RCP tariff and step downs in the RCP value. As indicated in Table 1 below, more residential solar capacity has been installed per customer in APS's service territory than any utility in the west, even surpassing all of the investor-owned utilities (IOUs) in California.[8] TEP also compares well with the California IOUs, with more residential solar capacity installed per residential customer than Southern California Edison.

Table 1 – Residential Solar Comparison

Residential solar comparison between APS, TEP and other utilities in the western U.S.
(as of the end of Q2 2020)

Utility	Watts of residential solar installed per residential customer	Total MWdc of residential solar installed	Total residential customers served by utility (millions)
Arizona Public Service	**849**	934	1.1
San Diego Gas & Electric	**813**	1,053	1.3
Pacific Gas & Electric	**560**	2,689	4.8
Tucson Electric Power	**499**	192	0.4
Southern California Edison	**437**	1,951	4.5
NV Energy	**389**	438	1.1
Rocky Mountain Power	**322**	263	0.8
PNM (NM)	**246**	115	0.5
Xcel Energy (CO)	**194**	185	1.0
Salt River Project	**181**	173	1.0

[8] Residential solar interconnection application and capacity installed data by utility service territory for Arizona Public Service, Salt River Project, and Tucson Electric Power sourced from Arizona Goes Solar - https://arizonagoessolar.org. Accessed on October 20th, 2020.

Residential solar capacity installed data by utility service territory for Pacific Gas and Electric, San Diego Gas and Electric, and Southern California Edison sourced from California Solar Statistics - https://www.californiadgstats.ca.gov/downloads/. Accessed on October 20th, 2020.

Residential solar capacity installed data by utility service territory for NV Energy, Rocky Mountain Power (Utah), Public Utility of New Mexico, and Xcel Energy (Colorado) sourced from the U.S. Energy Information Administration and available here https://www.eia.gov/electricity/data/eia861m/#netmeter. Accessed on October 20th, 2020.

Number of residential customers by utility from the U.S. Energy Information Administration -https://www.eia.gov/electricity/data.php. Accessed on October 20th, 2020.

Q. SHOULD THE COMMISSION ADOPT SEIA WITNESS LUCAS' RECOMMENDATION?

A. No. For the reason stated above, in the interest of all of APS's customers, the Commission should reject SEIA witness Lucas' recommendation.

VII. <u>THE OCOTILLO MODERNIZATION PROJECT (OMP)</u>

Q. PLEASE RECAP YOUR DIRECT TESTIMONY RELATED TO OMP.

A. As noted in my Direct Testimony, the OMP provides a number of benefits, including: reliable peaking capacity, flexibility to be able to integrate additional renewable resources, unique locational value in the APS load pocket, and it is also cleaner than the generation it is replacing.

Q. CAN YOU ADDRESS WHAT ROLE IF ANY THE OMP PLAYED IN RELIABLY SERVING YOUR CUSTOMERS THIS SUMMER, PARTICULARLY DURING THE AUGUST HEAT STORM?

A. As described in my Direct Testimony, the OMP was a prudent investment for APS customers. Staff, the Residential Utility Consumer Office, and Arizonans for Electric Choice and Competition all also include the asset in rate base as a part of their Direct Testimonies. This past summer highlights the value of a thermal peaking resource such as the OMP. During the heat storm where desert southwest utilities were declaring energy supply emergencies or issuing rolling blackouts (as discussed previously in my testimony), the OMP played an integral role in APS reliably serving the needs of customers. All five units were either providing energy to the system or providing necessary operating reserves during the high load hours on August 14th and 15th.

VIII. <u>CONCLUSION</u>

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

ATTACHMENT 4

REBUTTAL TESTIMONY OF ELIZABETH A. BLANKENSHIP

On Behalf of Arizona Public Service Company

Docket No. E-01345A-19-0236

November 6, 2020

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ATTACHMENT LIST

REBUTTAL TESTIMONY OF ELIZABETH A. BLANKENSHIP
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-19-0236)

I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Elizabeth A. Blankenship. I am the Vice President, Controller and Chief Accounting Officer for Arizona Public Service Company (APS or Company), a subsidiary of Pinnacle West Capital Corporation (Pinnacle West). I am primarily responsible for overseeing the financial accounting and reporting functions of the Company and Pinnacle West. My business address is 400 N. 5th Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS MATTER?

A. Yes. I filed direct testimony in this docket.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to address several adjustments to rate base and operating income proposed by Staff, the Residential Utility Consumer Office (RUCO), Arizonans for Electric Choice and Competition (AECC), and other intervenor witnesses. I will indicate in my rebuttal testimony where the Company is in agreement with their recommendations and will discuss those that I do not believe are accurate or appropriate. While I may not address every detail related to intervenors' recommendations, it should not be interpreted that I agree with each position unless specifically stated within my testimony. In addition, I will present the Company's updated information for many pro forma adjustments and provide the associated updated Standard Filing Requirements (SFR) Schedules.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Staff and intervenors in this case have proposed both rate base and operating income adjustments to the Company's original request. In some cases, these proposals are for reasonable revisions due to updated information that was not available at the time the Company filed its original request, or corrections and adjustments identified during the discovery process. Other adjustments that have been proposed are inaccurate or inappropriate, or both, and I discuss why these adjustments should either be revised or not accepted at all. Additionally, some proposed adjustments APS can accept in principle but require corrections, which I also discuss later in my Rebuttal Testimony. Finally, some Staff and intervenor operating income pro forma adjustments are addressed by APS witnesses Jacob Tetlow, Leland Snook, Jessica Hobbick, Dr. Ron White, and Barbara Lockwood in their Rebuttal Testimonies.

SFR Schedules A-1, B-1, B-2, C-1, C-2, and C-3 were updated to reflect the updated pro forma adjustments. SFR Schedules B-1 through C-3 are attached to my testimony as Attachment EAB-23RB through EAB-27RB, respectively, while SFR Schedule A-1 is attached to Mr. Snook's Rebuttal Testimony. I am sponsoring the Total Company column for those I have listed above and have discussed in my Rebuttal Testimony. All jurisdictional allocations shown on the SFRs are sponsored by APS witness Snook. The overall change in the Company's rate request, which includes these revisions, is addressed by APS witnesses Lockwood and Snook in their Rebuttal Testimonies.

III. ITEMS OF AGREEMENT

Q. DOES APS AGREE WITH THE METHODOLOGY USED IN STAFF WITNESS RALPH SMITH'S CASH WORKING CAPITAL ADJUSTMENTS?

A. Yes. APS has reviewed the Cash Working Capital (CWC) adjustments proposed by Staff witness Smith and agrees that the calculations are consistent with Staff's Test Year revenues and expenses. As discussed below, APS is proposing changes to pro forma adjustments and those updates are reflected in the Company's CWC adjustment, following the same methodology APS used in the initial filing and containing the values proposed in my testimony. *See* Attachment EAB-07RB and Attachment EAB-08RB.

Q. DOES APS AGREE WITH STAFF WITNESS SMITH'S ADJUSTMENT TO REMOVE GROWTH RELATED METERS FROM POST-TEST YEAR PLANT?

A. Yes, APS agrees with and accepts Staff's adjustment to remove growth-related meters from post-Test Year plant (PTYP) amounts, with a slight additional correction. APS had intended to remove all growth-related items from PTYP, but inadvertently included $4.3 million of meters related to growth, which is slightly higher than the $4.1 million proposed by Staff witness Smith. The difference between the actual amount removed by APS of $4.3 million and the amount proposed by Staff witness Smith of $4.1 million is a result of the update to actuals through June 30, 2020. APS updated the calculation to remove the plant and the corresponding depreciation, accumulated deferred income taxes (ADIT) and property tax effects and has provided the new information on Attachment EAB-01RB and Attachment EAB-02RB.

Q. DOES APS AGREE WITH STAFF WITNESS SMITH'S ADJUSTMENT TO REMOVE ACCUMULATED DEPRECIATION AND EXPENSES

RELATED TO THE DAMAGED AND RETIRED MCMICKEN BATTERY ENERGY STORAGE FACILITY?

A. Yes. APS agrees with and accepts Staff's adjustments to remove the accumulated depreciation balance and expenses related to the damaged and retired McMicken Battery Energy Storage Facility. APS revised the O&M adjustment of $359,000 provided in Staff witness Smith's testimony to reflect updated expenses of $659,000. *See* Attachment EAB-20RB and Attachment EAB-21RB.

Q. DOES APS AGREE WITH STAFF WITNESS SMITH'S ADJUSTMENT TO REMOVE UTILITY SOLID WASTE GROUP (USWAG) AND UTILITY AIR REGULATORY GROUP (UARG) DUES AS WELL AS BAIN CONSULTING COSTS?

A. Yes. APS agrees with and accepts Staff's adjustments to remove the USWAG and UARG membership dues totaling $233,159 and additional Bain consulting costs totaling $695,000 from Test Year operating expenses in accounts 9302000 and 9200000, respectively. *See* Attachment EAB-15RB.

Q. AECC WITNESS KEVIN HIGGINS HAS PROPOSED AN ADJUSTMENT TO TEST YEAR EXPENSES TO REVISE THE PENSION AND OTHER POST RETIREMENT EMPLOYEE BENEFIT (OPEB) EXPENSES BY USING THE AVERAGE OF THE 2019 EXPENSE AND PROJECTED 2020 EXPENSE. IS THIS REASONABLE?

A. Yes. APS accepts AECC witness Higgins' adjustment to calculate the Pension and OPEB expense using the average of the 2019 expense and projected 2020 expense. APS has historically utilized the actual annual level of cost as estimated by the Company's actuaries, Willis Towers Watson, to derive the adjustment. This methodology is consistent with the way the company measures and calculates the pension obligation and related expense on an annual basis. Utilizing AECC witness Higgins' methodology of calculating the cost using the actual 2019 expense and projected 2020 expense results in a Total Company reduction to operating income of $10.5 million, which is in agreement with AECC's Total Company operating income adjustment. *See* Attachment EAB-16RB.

IV. <u>UPDATES TO PRO FORMA ADJUSTMENTS TO THE TEST YEAR</u>

Q. IS APS UPDATING ANY PRO FORMA ADJUSTMENTS FOR ITS REBUTTAL TESTIMONY?

A. Yes. APS is updating pro forma adjustments to reflect actual costs to date, known adjustments identified in the discovery process, and to include the effects and synchronize the updated pro formas. The following pro formas will be updated:

- *PTYP* – see section below for a discussion on the updates included (*see* Attachment EAB-01RB, SFR Schedule B-2 (Attachment EAB-24RB), columns 2-6 and Attachment EAB-02RB, SFR Schedule C-2 (Attachment EAB-26RB), columns 1-5)

- *Property Tax Deferral* – updated to reflect final 2019 composite tax rate, estimated 2020 composite tax rate and amortization period of three (3) years instead of ten (10) due to the deferral being a refund to customers (*see* Attachment EAB-03RB, SFR Schedule B-2 (Attachment EAB-24RB), column 9 and Attachment EAB-04RB, SFR Schedule C-2 (Attachment EAB-26RB), column 41)

- *Annualized Property Tax Expense* - updated to reflect final 2019 composite tax rate (*see* Attachment EAB-05RB and SFR Schedule C-2 (Attachment EAB-26RB), column 40)

- *Depreciation Expense* – updated to reflect updated depreciation study rates provided in APS witness White's Rebuttal Testimony (*see* Attachment EAB-06RB, SFR Schedule C-2 (Attachment EAB-26RB), column 33)

- *Cash Working Capital* – updated to reflect all updated and new pro forma adjustments (*see* Attachment EAB-07RB, SFR Schedule B-2 (Attachment EAB-24RB), column 10 and Attachment EAB-08RB, SFR Schedule C-2 (Attachment EAB-26RB), column 45)

- *West Phoenix 4 Disallowance* – updated for known adjustments identified in the discovery process *(see* Attachment EAB-09RB, SFR Schedule B-2 (Attachment EAB-24RB), column 8 and Attachment EAB-10RB, SFR Schedule C-2 (Attachment EAB-26RB), column 29)

- *Four Corners Selective Catalytic Reduction (SCR) Deferral* – updated to include actual costs through September 30, 2020 and known adjustments identified in the discovery process *(see* Attachment EAB-11RB, SFR Schedule B-2 (Attachment EAB-24RB), column 12 and Attachment EAB-12RB,SFR Schedule C-2 (Attachment EAB-26RB), column 25)

- *Ocotillo Modernization Project (OMP) Deferral* – updated to include actual costs through September 30, 2020 and known adjustments identified in the discovery process *(see* Attachment EAB-13RB, SFR Schedule B-2 (Attachment EAB-24RB), column 11 and Attachment EAB-14RB,SFR Schedule C-2 (Attachment EAB-26RB), column 26)

- *Out of Period and Miscellaneous Items* – updated for known adjustments identified in the discovery process to remove additional Bain consulting costs and USWAG and UARG dues previously discussed *(see* Attachment EAB-15RB,SFR Schedule C-2 (Attachment EAB-26RB), column 50)

- *Normalize Employee Benefits* – updated to reflect the averaging of the 2019 actual and 2020 estimated Pension and OPEB costs *(see* Attachment EAB-16RB, SFR Schedule C-2 (Attachment EAB-26RB), column 35)

- *Excess Deferred Tax* – updated to reflect amortization pursuant to Decision No. 77464, Reconstructed Cost New Less Depreciation, and Total Company amounts to include FERC jurisdictional excess deferred taxes *(see* Attachment EAB-17RB, SFR Schedule B-2 (Attachment EAB-24RB), column 13)

- *Tax Expense Adjustment Mechanism (TEAM) Balancing Account* – new pro forma adjustment to account for the balancing accounts associated with TEAM I, II and III and the amortization of those costs *(see* Attachment EAB-18RB, SFR Schedule B-2 (Attachment EAB-24RB), column 14 and Attachment EAB-19RB, SFR Schedule C-2 (Attachment EAB-26RB), column 53)

- *Remove Test Year McMicken Battery Costs* – new pro forma adjustment to remove the costs associated with the McMicken Battery contained in the

Test Year and as also previously discussed *(see* Attachment EAB-20RB, SFR Schedule B-2 (Attachment EAB-24RB), column 15 and Attachment EAB-21RB, SFR Schedule C-2 (Attachment EAB-26RB), column 54)

- *Interest Expense on Customer Deposits Update* – updated to reflect the current customer deposit interest rate that became effective on January 3, 2020 *(see* Attachment EAB-22RB, SFR Schedule C-2 (Attachment EAB-26RB), column 32)

Q. AECC WITNESS HIGGINS HAS CRITICIZED SOME OF THE COMPANY'S PRO FORMA ADJUSTMENTS TO THE TEST YEAR AS TOO AGGRESSIVE. DOES APS BELIEVE THAT THE COMPANY'S PRO FORMA ADJUSTMENTS ACCURATELY REFLECT THE CONDITIONS DURING THE PERIOD IN WHICH RATES ARE ESTIMATED TO BE IN EFFECT?

A. Yes. APS believes that the pro forma adjustments included in the application and supplemented as part of this Rebuttal Testimony collectively reflect the conditions for the period in which rates are expected to be in effect. APS disagrees with AECC's position that APS should not be adjusting the historical Test Year "for values that either occurred or are projected to occur variously in 2019 or 2020."[1] AECC's proposal does not properly reflect an accurate level of costs and savings during the period in which rates are in effect.

As stated in my Direct Testimony, pro forma adjustments are adjustments made to the historical Test Year to properly reflect accurate conditions and an on-going level of expected costs during the period in which rates are to be in effect. Because a historical test year is utilized in Arizona, it is necessary to make these

[1] *See* AECC Direct Testimony of Kevin C. Higgins at 8 (Oct. 2, 2020).

types of adjustments for known and measurable changes that have occurred. To exclude these, and therefore not adjust rate base and costs in the historical test period, would be a disservice not only to APS, but to customers, as many of the pro forma adjustments result in reductions to revenue requirement and reduce the rates customers may ultimately pay. For example, pro forma adjustments included by APS adjust the Test Year to remove one-time or nonrecurring costs, such as operating and maintenance costs that will no longer be incurred after the historical Test Year as a result of a plant closure. They also adjust the Test Year for an ongoing level of costs that have decreased after the historical Test Year, such as coal reclamation costs. Additionally, and of significance, are those pro forma adjustments that remove or reduce certain costs from the Test Year in which forecasted savings or cost reduction is anticipated to occur, such as Customer Affordability. These pro forma examples are just a few of the pro forma adjustments which result in a reduction in revenue requirement.

V. PTYP ADDITIONS

Q. IS APS PROPOSING AN UPDATE TO ITS PTYP ADJUSTMENT?

A. Yes. APS reduced the PTYP proposed to be included in rate base by a total of $66.2 million with a corresponding reduction to pre-tax operating income totaling $6.9 million. *See* Attachment EAB-01RB and EAB-02RB for the updated PTYP information. APS's proposed adjustments to PTYP consist of three updates including of 1) updates for actual amounts through June 30, 2020; 2) revised depreciation rates; and 3) updates to recognize Staff witness Smith's adjustment to remove $4.3 million of growth-related meters. These adjustments are further described as follows:

- The adjustment to update for actual amounts through June 30, 2020 results in a rate base reduction of $88.7 million and a corresponding reduction to pre-tax operating income of $6.4 million;

- The adjustment for revised depreciation rates, as discussed further below, results in a rate base increase of $26.8 million and a reduction to pre-tax operating income of $0.7 million; and

- The adjustment to remove growth-related meters, as discussed above, results in a net rate base reduction of $4.3 million with a minimal impact to pre-tax operating income.

APS witnesses Tetlow and Snook also rebut certain PTYP related issues in their testimonies.

Q. DOES APS AGREE WITH RUCO WITNESS FRANK RADIGAN'S POSITION ON PTYP?

A. Partially. APS generally agrees with RUCO witness Radigan that, for PTYP to be included and considered, it must normally be in service by the end of the post-Test Year period and that the plant must be used and useful. The plant additions the Company has included in its PTYP (July 1, 2019 through June 30, 2020) are those that are already in service, used and useful, and providing benefits to customers today. APS also agrees with RUCO witness Radigan that the Company is trying to find an appropriate balance between timely cost recovery and customer bill impacts. Avoiding potential overlap between growth and PTYP through the exclusion of revenue producing or growth-related plant investments, and including accumulated depreciation related to plant-in-service at the end of the test period, both result in a reduction to the Company's revenue requirement.

However, APS disagrees with RUCO witness Radigan's position that certain investments should be excluded from consideration solely based on size and the supposed impact on the financial health of the Company. The dollar amount of the investment does not, in and of itself, establish the value and benefit to the customer, which is discussed in more detail by APS witness Tetlow.

Furthermore, APS disagrees with RUCO witness Radigan's position that the Test Year accumulated depreciation be further adjusted to reflect depreciation on PTYP during the post-Test Year period. APS includes accumulated depreciation, 12-months of annualized depreciation expense computed using the Test Year plant balance, and proposed depreciation rates as part of PTYP. The Company believes that this fairly represents ongoing accumulated depreciation in PTYP and is consistent with methods accepted in prior rate case filings.

Q. DOES APS BELIEVE IT IS APPROPRIATE TO DISALLOW PROPERTY TAX ON PTYP ADDITIONS AS RUCO WITNESS RADIGAN ASSERTS?[2]

A. No. The allowance of property tax on PTYP additions is consistent with Decision Nos. 71448 (Dec. 30, 2009), 73183 (May 24, 2012) and 76295 (Aug. 18, 2017). Inclusion of property taxes represents known and measurable amounts, and best reflects the ongoing anticipated expense between when new rates go into effect and the next rate case. If property taxes are not allowed on PTYP additions, APS will have no method of recovery for the known and measurable amount that will be incurred as a result of these additions in the first full year rates would be in effect.

As stated in my Direct Testimony, in accordance with Paragraph 11.5 of the Settlement Agreement in APS's last rate case, APS met and conferred with Staff and RUCO in September 2019 and discussed APS's plan to consistently include property taxes for PTYP. This is in line with other utilities and public utility commission decisions and gives customers the benefit of the lag between assessment and payment of property taxes in the cash working capital lead/lag study, which has the effect of reducing rate base. If RUCO witness Radigan's disallowance of property taxes on PTYP is adopted, APS's cash working capital

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[2] *See* RUCO Direct Testimony of Frank W. Radigan at 17 (Oct. 2, 2020).

allowance, and hence its rate base, would need to be increased accordingly. The Company's position on this issue is further supported by Staff witness Smith in his filed Direct Testimony.

VI. <u>DEPRECIATION</u>

Q. DO YOU AGREE WITH RUCO WITNESS RADIGAN'S PROPOSALS TO REDUCE THE NET PLANT BY APPROXIMATELY $399 MILLION AND THE RELATED REDUCTION IN THE STEAM PRODUCTION DEPRECIATION ACCRUAL OF $27.6 MILLION REPORTED IN THE COMPANY'S DEPRECIATION STUDY RELATED TO THE FOUR CORNERS SCR INVESTMENT?

A. No. As discussed in the Direct and Rebuttal Testimonies of APS witness Lockwood, the Company believes that the Four Corners SCR investment was reasonable and prudent and should be included in rate base for this case. As such, the net plant balance and associated increase in the depreciation expense accrual contained in APS witness White's study are stated accordingly. Please see Direct and Rebuttal Testimonies of APS witnesses Lockwood and White.

Q. RUCO WITNESS RADIGAN ALSO PROPOSES AN ADJUSTMENT OF $27.9 MILLION RELATED TO AVERAGE SERVICE LIVES AND NET SALVAGE RATES FOR DISTRIBUTION PLANT. DOES APS ACCEPT THIS ADJUSTMENT?

A. No. APS supports the proposed service lives and net salvage rates determined by APS witness White for all distribution plant accounts. Please see APS witness White's Rebuttal Testimony for more information.

Q. IS APS PROPOSING AN UPDATE TO ITS ANNUALIZED DEPRECIATION EXPENSE ADJUSTMENT?

A. Yes, APS is proposing to reduce its pre-tax operating income by $26.8 million. *See* Attachment EAB-06RB. APS is proposing this reduction to reflect updated depreciation study rates provided in APS witness White's Rebuttal Testimony.

VII. PENSION AND OTHER POST RETIREMENT EMPLOYEE BENEFITS (OPEB)

Q. IS APS APPLYING THE STANDARD RATEMAKING TREATMENT OF PREPAYMENT AND UNFUNDED LIABILITIES RELATED TO PENSION AND OPEB IN THIS CASE?

A. Yes. As presented in SFR Schedule B-1, the Company is and has historically included both the net pension asset and net OPEB liability in rate base as an increase and reduction, respectively. Because the pension regulatory asset or "prepaid pension asset" is larger than the unfunded liability, the Company has a net regulatory asset and therefore an increase to rate base. Conversely, the OPEB (net regulatory liability) represents a net decrease to rate base. With respect to the Company's qualified pension plan, the Company has contributed more dollars to the plan than it has recognized in actuarially calculated pension expense, resulting in the regulatory asset balance or "prepaid pension asset." Conversely, the OPEB regulatory liability is associated with the retiree medical and post-employment benefits in which the Company has contributed less than the actuarially calculated expense. Both the Pension and OPEB rate base amounts are offset by the accumulated deferred income tax amounts (ADIT) associated with those assets and liabilities. The Company earns a return only on the remaining portion after the ADIT are subtracted. Table 1 below presents the respective rate base components. The net amount as presented in Table 1 is appropriate to include in the Company's rate base as it represents shareholder capital that is being used for the benefit of customers.

Table 1.

Description Pension & OPEB Rate Base Items as of 6/30/19 ($ in Millions)	Total Company
Pension Regulatory Asset	$712.9
OPEB Regulatory Liability	(143.0)
Pension Liability (underfunded)	(305.2)
OPEB Asset (overfunded)	52.6
Net Deferred Tax Liability	(123.3)
Net Rate Base	$194.0

Q. DOES APS AGREE WITH AECC WITNESS HIGGINS AND FEA WITNESS MICHAEL GORMAN THAT PENSION AND OPEB RATE BASE ITEMS SHOULD BE REMOVED?

A. No. It is appropriate to include the Pension and OPEB in rate base for several reasons. First, it is customary for prepayments to be included in rate base, regardless of whether they are prepayments by the utility (increases to rate base) or by its customers (reductions to rate base). There is no reason to treat the net prepayment in this case differently. Second, customers are earning a return on the pension regulatory asset or "prepaid pension asset," and therefore it is appropriate that the Company earn a return on its net prepayment as well. Customers are earning a return as a result of the annual pension cost, which includes an expected return on assets (EROA). The return is reflected as a decrease in annual pension cost.

Q. HOW ARE CUSTOMERS BENEFITING FROM THE EROA COMPONENT OF ANNUAL PENSION COST?

A. The EROA percentage is multiplied by the value of the assets in the pension trust, and the product of that calculation is subtracted from the annual pension cost. Therefore, customers receive the benefit of the earnings on the entire amount of the assets in the pension trust, not just the amount that has been recognized in annual pension cost. Stated another way, customers are receiving a return on amounts that they have not yet paid through recognized pension cost. In effect, the Company has made a prepayment of pension contributions, and customers are earning a return on that prepayment through the EROA. It would therefore be inequitable and unreasonable to deny the Company a return on the pension regulatory asset or "prepaid pension asset."

Additionally, to say that these rate base items have not been specifically brought before the Commission in prior rate cases is incorrect. The Pension and OPEB rate base components have been presented to the Commission and intervenors by specifically disclosing them on the face and supporting schedules of SFR Schedule B-1. Prior to this proceeding, no party has questioned the rate base treatment of these regulatory assets and liabilities.

VIII. <u>SCR AND OMP DEFERRALS</u>

Q. WHY IS IT REASONABLE FOR THE COMPANY TO INCLUDE THE SCR AND OMP RATE BASE AND INCOME STATEMENT DEFERRALS IN THE RATE APPLICATION?

A. As previously discussed in my Direct Testimony and further supported by Staff witness Smith's Direct Testimony, as part of the Settlement Agreement approved in Decision No. 76295, the Company was authorized to defer for later recovery the costs related to the SCR equipment and OMP.

In regards to the SCRs, Section 9.3 of Exhibit A in Decision No. 76295 stated that, "[t]he Signing Parties agree to use good faith efforts to process this rate adjustment request such that any resulting rate adjustment becomes effective no later than January 1, 2019." While the Signing Parties to the Settlement Agreement did in fact use good faith efforts to process the Four Corners SCR rate adjustment so that it would be effective by January 1, 2019, and a Recommended Opinion and Order was issued by the Administrative Law Judge recommending approval of the request with minor modifications, a final decision has not occurred.[3] As such, the Company is not currently receiving cost recovery of that deferral. Thus, APS agrees with Staff witness Smith that inclusion of these expenses in the current proceeding is appropriate.

In regards to OMP, Section 10.2 of Exhibit A in Decision No. 76295 stated that, "[]he entire OMP will be in service before the rate effective date of APS's next general rate case, and the entire OMP investment will be addressed and resolved in that proceeding." As such, the Company has included the rate base and income statement deferrals in this rate case application for consideration and to support Staff's ongoing and continued review.

Q. DO YOU AGREE WITH RUCO WITNESS RADIGAN'S PROPOSAL TO REMOVE THE SCR PRO FORMA ADJUSTMENTS FROM RATE BASE AND COST OF SERVICE?

A. No, APS does not agree with Mr. Radigan's proposal for the reasons discussed above. Additionally, the investment in the Four Corners SCRs was previously supported by RUCO as prudent, is indisputably used and useful, and will continue to benefit customers. Please see the Rebuttal Testimony of APS witness

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[3] Recommended Opinion and Order (November 27, 2018), Docket No. E-01345A-16-0036 et.al.

Lockwood for more information related to the prudency of the Four Corners SCRs.

Q. DID THE COMPANY MAKE ANY CHANGES TO THE SCR AND OMP DEFERRAL PRO FORMAS?

A. Yes, APS updated the SCR and OMP deferral pro formas to include actual costs through September 30, 2020 and known adjustments identified in the discovery process, which resulted in a rate base reduction of $429,000 and increase of $2.4 million, respectively. The corresponding operating income effects were a reduction of $84,000 and increase of $197,000 for the SCR and OMP deferrals, respectively. While this update and change is in alignment with Staff witness Smith's recommendation, there is a small difference between APS's updated amounts and Staff's as a result of APS's further updating the amounts with actuals through September 30, 2020. Previous updates as provided to Staff in the discovery process included updates only through June 30, 2020.

Q. WILL APS CONTINUE TO DEFER COSTS RELATED TO THE SCR AND OMP THROUGH THE RATE EFFECTIVE DATE AND ADDRESS ANY DIFFERENTIAL IN THE NEXT RATE CASE APPLICATION?

A. Yes, in filing the rate case application as directed, the Company assumed a rate effective date of January 1, 2021 based on procedural schedule precedence. In the interest of not increasing the revenue requirement impact to customers in this rate case, the Company has not updated the deferral rate base and income statement pro formas related to the SCR and OMP deferrals with a new estimated rate effective date. APS will continue the deferral until the rate effective date and will address these additional deferrals, with balances from January 1, 2021 until the rate effective date, in the Company's next rate case proceeding.

IX. INCENTIVE COMPENSATION

Q. DOES APS AGREE WITH RUCO WITNESS RADIGAN, AECC WITNESS HIGGINS AND STAFF WITNESS SMITH REGARDING DISALLOWANCE OF CASH INCENTIVE COMPENSATION?

A. No, the cash incentive is a valid cost that APS has incurred for employee compensation. APS pays for performance, and the cash incentive is an identified portion of the APS compensation available to employees for their participation in meeting goals that align the success of the business with the interests of APS customers. RUCO witness Radigan, AECC witness Higgins, Staff witness Smith, nor any other intervenor in the docket, have even alleged, let alone provided any evidence, that APS's overall employee compensation is by some standard "excessive" or "unreasonable." The above-mentioned witnesses' arbitrary proposals result in a disallowance of prudent costs that ultimately benefit customers, and therefore APS continues to support the three-year normalization and full recovery of cash incentive compensation.

Q. DO YOU AGREE WITH AECC WITNESS HIGGINS' OPINION THAT THE FINANCIAL PERFORMANCE COMPONENT OF AN INCENTIVE PLAN SHOULD NOT BE RECOVERED THROUGH UTILITY RATES?

A. No, these financial targets and goals directly benefit customers through reduced rates as costs are effectively reduced. While APS can agree with AECC witness Higgins' opinion that it is appropriate that an incentive plan include goals such as customer satisfaction, operating efficiency and safety, and that rewarding employees for financial performance can be entirely appropriate, the Company does not agree with his opinion that shareholders are the primary beneficiaries of financial targets.

X. MISCELLANEOUS

Q. DOES APS AGREE WITH STAFF WITNESS SMITH'S AND RUCO WITNESS RADIGAN'S PROPOSALS TO DISALLOW DIFFERENT PORTIONS OF EXECUTIVE COMPENSATION?

A. No, APS does not agree with the proposed disallowance of prudent costs incurred by the Company that are necessary to attract and retain qualified directors and officers, all of which provide benefit to customers. Please also see the Rebuttal Testimony of APS witness Guldner for more information on executive compensation.

XI. PROPERTY TAX DEFERRAL

Q. IS APS PROPOSING AN UPDATE TO ITS PROPERTY TAX DEFERRAL PRO FORMA ADJUSTMENTS?

A. Yes. APS updated the property tax deferral, resulting in a rate base reduction of \$6.1 million with a corresponding reduction to pre-tax operating income of S4.2 million. *See* Attachments EAB-03RB and EAB-04RB for the updated property tax information. APS is proposing this adjustment to reflect the final 2019 composite property tax rate, estimated 2020 composite property tax rate and an amortization period of three (3) years instead of ten (10) years due to the deferral being a refund to customers.

Q. DOES APS AGREE WITH PROPOSALS TO DISCONTINUE THE PROPERTY TAX DEFERRAL?

A. No. Property taxes can fluctuate significantly year-over-year and represent costs that the Company cannot control. APS believes it necessary to have a mechanism in place to allow at least the potential for future recovery or refund to customers through rates. Allowing APS to defer these costs does not impact this case and does not guarantee recovery in subsequent rate cases. The property tax deferral merely preserves APS's ability to recover or refund these costs should the

Commission find them reasonable and prudent at the time actual recovery is sought.

XII. UPDATED STANDARD FILING REQUIREMENTS

Q. IS APS FILING UPDATED STANDARD FILING REQUIREMENTS TO REFLECT THE PRO FORMA ADJUSTMENTS DISCUSSED ABOVE?

A. Yes. APS is filing SFR Schedules A-1, B-1, B-2, C-1, C-2 and C-3 (Attachment LRS-02RB and Attachments EAB-23RB through EAB-27RB) to reflect the pro forma adjustments and other updates provided in rebuttal.

XIII. CONCLUSION

Q. DO YOU HAVE ANY FINAL COMMENTS?

A. Yes. I have addressed a number of operating income and rate base adjustments proposed by Staff and various intervenors in this case – agreeing with some, disagreeing or at times correcting others. In each instance, my goal is to make the Adjusted Test Year more representative of the period of time rates will become effective. I have introduced SFR Schedules A-1, B-1, B-2, C-1, C-2 and C-3 (Attachment LRS-02RB and Attachments EAB-23RB through EAB-27RB) which are updated to reflect the updated pro forma adjustments. These updated SFRs represent an accurate basis upon which the Commission can establish just and reasonable rates.

Q. DOES THIS CONCLUDE YOUR WRITTEN REBUTTAL TESTIMONY?

A. Yes.

Arizona Public Service Company
Rate Base Pro Forma Adjustments
Test Year Ended 6/30/2019 - UPDATED FOR REBUTTAL
(Dollars in Thousands)

		UPDATED FOR REBUTTAL					
		Total Company					
Line No.	Description	Fossil Generation Post-Test Year Plant Additions	Nuclear Generation Post-Test Year Plant Additions	Distribution and IT Facilities Post-Test Year Plant Additions	Renewables Post-Test Year Plant Additions	Technology Innovation Post-Test Year Plant Additions	Total Company Post-Test Year Plant Additions
1.	Gross Utility Plant in Service	$ 216,918	$ 67,708	$ 418,060	$ 17,048	$ 14,187	$ 733,921
2.	Less: Accumulated Depreciation and Amortization	201,688	17,283	287,026	25,604	-	531,601
3.	Net Utility Plant in Service	15,230	50,425	131,034	(8,556)	14,187	202,320
4.	Less: Total Deductions	663,748	4,447	(2,712)	2,485	(150)	72,814
5.	Total Additions	-	-	-	436	-	436
6.	Total Rate Base	$ (48,518)	$ 45,978	$ 59,178	$ (10,605)	$ 14,337	$ 129,942

Rebuttal adjustments to Test Year rate base to include actual depreciation, interest expense, property taxes and reduced income tax expense associated with post-Test Year plant additions.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 6/30/2019 - UPDATED FOR REBUTTAL
(Dollars in Thousands)

Line No.	Description		UPDATED FOR REBUTTAL Total Company: Fossil Generation Post-Test Year Plant Additions	Nuclear Generation Post-Test Year Plant Additions	Distribution and IT/Facilities Post-Test Year Plant Additions	Technology Innovation Post-Test Year Plant Additions	Renewables Post-Test Year Plant Additions	Total Company Post-Test Year Plant Additions
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		-	-	-	-	-	-
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		-	-	-	-	-	-
10.	Depreciation and Amortization		9,551	210	21,794	1,419	506	33,480
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		1,442	453	8,018	265	67	10,245
14.	Total Other Operating Expense		10,993	663	29,812	1,684	573	43,725
15.	Operating Income Before Income Tax		(10,993)	(663)	(29,812)	(1,684)	(573)	(43,725)
16.	Interest Expense		283	938	2,437	264	(159)	3,763
17.	Taxable Income		(11,276)	(1,601)	(32,249)	(1,948)	(414)	(47,488)
18.	Current Income Tax Rate	24.75%	(2,791)	(396)	(7,982)	(482)	(103)	(11,754)
19.	Operating Income (line 15 minus line 18)		$ (8,202)	$ (267)	$ (21,830)	$ (1,202)	$ (470)	$ (31,971)

Rebuttal adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with post-Test Year Plant Additions.

ARIZONA PUBLIC SERVICE COMPANY
Rate Base Pro Forma Adjustments
Test Year Ended 06/30/2019 - UPDATED FOR REBUTTAL
(Dollars in Thousands)

Line No.	Description	UPDATED FOR REBUTTAL Include Property Tax Deferral Total Co.
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation & Amort.	-
3.	Net Utility Plant in Service	-
4.	Less: Total Deductions	(2,551)
5.	Total Additions	(10,308)
6.	Total Rate Base	$ (7,757)

Rebuttal adjustment to Test Year rate base to annualize property taxes calculated using the actual 2019 composite tax rate.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 06/30/2019 - UPDATED FOR REBUTTAL
(Dollars in Thousands)

Line No.	Description		UPDATED FOR REBUTTAL Property Tax Deferral Amortization Total Co.
	Electric Operating Revenues		
1.	Revenues from Base Rates		$ -
2.	Revenues from Surcharges		-
3.	Other Electric Revenues		-
4.	Total Electric Operating Revenues		-
5.	Electric Fuel and Purchased Power Costs		-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-
	Other Operating Expenses:		
7.	Operations Excluding Fuel Expense		-
8.	Maintenance		-
9.	Subtotal		-
10.	Depreciation and Amortization		-
11.	Amortization of Gain		-
12.	Administrative and General		-
13.	Other Taxes		(4,671)
14.	Total Other Operating Expense		(4,671)
15.	Operating Income Before Income Tax		4,671
16.	Interest Expense		(151)
17.	Taxable Income		4,822
18.	Current Income Tax Rate -	24.75%	1,193
19.	Operating Income (line 15 minus line 18)		$ 3,478

Rebuttal adjustment to amortize the property tax deferral as authorized in Decision No. 76295 over 3 years rather than 10 years.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 06/30/2019 - UPDATED FOR REBUTTAL
(Dollars in Thousands)

Line No.	Description		UPDATED FOR REBUTTAL Annualize Property Tax Expense Total Co.
1.	Electric Operating Revenues		$ -
2.			
3.	Fuel Expense		-
4.	Oper Rev Less Fuel		-
5.	Operating Expenses:		
6.	Operations Excluding Fuel Expenses		-
7.	Maintenance		-
8.	Subtotal		-
9.	Depreciation and Amortization		-
10.	Amortization of Gain		-
11.	Administrative and General		-
12.	Other Taxes		2,750
13.	Total		2,750
14.	Operating Income Before Income Tax		(2,750)
15.	Net Deductions		-
16.	Interest Expense		-
17.	Taxable Income		(2,750)
18.	Current Income Tax Rate -	24.75%	(681)
19.	Deferred Tax		-
20.	Operating Income After Tax		$ (2,069)

Rebuttal adjustment to Test Year operations to annualize property taxes calculated using the actual 2019 composite tax rate.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 06/30/19 - UPDATED FOR REBUTTAL
(Dollars in Thousands)

Line No.	Description		UPDATED FOR REBUTTAL Depreciation Expense
1.	Electric Operating Revenues	$	-
2.			
3.	Fuel Expense		-
4.	Oper Rev Less Fuel		
5.	Operating Expenses:		
6.	Operations Excluding Fuel Expenses		-
7.	Maintenance		-
8.	Subtotal		-
9.	Depreciation and Amortization		62,940
10.	Amortization of Gain		-
11.	Administrative and General		-
12.	Other Taxes		-
13.	Total		62,940
14.	Operating Income Before Income Tax		(62,940)
15.	Net Deductions		-
16.	Interest Expense		-
17.	Taxable Income		(62,940)
18.	Current Income Tax Rate - 24.75%		(15,578)
19.	Deferred Tax		-
20.	Operating Income After Tax	$	(47,362)

Rebuttal adjustment to Test Year operations to reflect updated depreciation study rates based on revisions to the 2019 Depreciation Rate Study.

ARIZONA PUBLIC SERVICE COMPANY
Pro Forma Adjustments to Original Cost Rate Base
Test Year Ended 6/30/2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	UPDATED FOR REBUTTAL Adjust Cash Working Capital Total Co.
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation and Amortization	-
3.	Net Utility Plant in Service	-
4.	Less: Total Deductions	-
5.	Total Additions	(8,608)
6.	Total Rate Base	$ (8,608)

Rebuttal adjustment for updates to cash working capital rate base pro forma adjustment.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 6/30/2019 - UPDATED FOR REBUTTAL
(Dollars in Thousands)

Line No.	Description	UPDATED FOR REBUTTAL Adjust Cash Working Capital for Cost of Service Pro Formas
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	-
15.	Operating Income Before Income Tax	-
16.	Interest Expense	(160)
17.	Taxable Income	160
18.	Current Income Tax Rate - 24.75%	40
19.	Operating Income (line 15 minus line 18)	$ (40)

Rebuttal adjustment to Test Year interest expensefor updates to cash working capital rate base pro forma adjustment.

ARIZONA PUBLIC SERVICE COMPANY
Rate Base Pro forma Adjustments
Test Year Ended 6/30/2019 - UPDATED FOR REBUTTAL
(Dollars in Thousands)

Line No.	Description		UPDATED FOR REBUTTAL Include West Phoenix CC Unit #4 Regulatory Disallowance Total Co.
1.	Gross Utility Plant in Service	$	(13,833)
2.	Less: Accumulated Depreciation & Amort.		(6,432)
3.	Net Utility Plant in Service		(7,401)
4.	Less: Total Deductions		(1,514)
5.	Total Additions		-
6.	Total Rate Base	$	(5,887)

Adjustment to Test Year rate base to reflect amortization of regulatory disallowance for West Phoenix CC Unit 4 over the remaining life as required by ACC Decision Nos. 67744 and 69663.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 6/30/2019 - UPDATED FOR REBUTTAL
(Dollars in Thousands)

Line No.	Description		UPDATED FOR REBUTTAL Include West Phoenix Unit 4 Regulatory Disallowance
	Electric Operating Revenues		
1.	Revenues from Base Rates	$	-
2.	Revenues from Surcharges		-
3.	Other Electric Revenues		-
4.	Total Electric Operating Revenues		-
5.	Electric Fuel and Purchased Power Costs		-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-
	Other Operating Expenses:		
7.	Operations Excluding Fuel Expense		-
8.	Maintenance		-
9.	Subtotal		-
10.	Depreciation and Amortization		(329)
11.	Amortization of Gain		-
12.	Administrative and General		-
13.	Other Taxes		-
14.	Total Other Operating Expenses		(329)
15.	Operating Income Before Income Tax		329
16.	Interest Expense		(110)
17.	Taxable Income		439
18.	Current Income Tax Rate - 24.75%		109
19.	Operating Income (line 15 minus line 18)	$	220

Rebuttal adjustment to Test Year operations to reflect amortization of regulatory disallowance of West Phoenix Unit 4 over the remaining life of the plant as required by previous ACC Decision Nos. 67744 and 69663. The correction does not show due to rounding to thousands.

ARIZONA PUBLIC SERVICE COMPANY
Pro Forma Adjustments to Original Cost Rate Base
Test Year Ended 6/30/19 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	UPDATED FOR REBUTTAL **Four Corners SCR Deferral** Total Co.
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation and Amortization	-
3.	Net Utility Plant in Service	-
4.	Less: Total Deductions	10,779
5.	Total Additions	43,550
6.	Total Rate Base	$ 32,771

Rebuttal adjustment to Test Year operations to include actual amortization of the Four Corners SCR deferral through 9/30/2020 and estimated amortization through 12/31/2020.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 6/30/2019 - UPDATED FOR REBUTTAL
(Dollars in Thousands)

Line No.	Description	UPDATED FOR REBUTTAL **Four Corners Deferral** Total Co.
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	8,147
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	8,147
15.	Operating Income Before Income Tax	(8,147)
16.	Interest Expense	-
17.	Taxable Income	(8,147)
18.	Current Income Tax Rate - **24.75%**	(2,016)
19.	Operating Income (line 15 minus line 18)	$ (6,131)

Rebuttal adjustment to Test Year operations to include actual amortization of the Four Corners SCR deferral through 9/30/2020 and estimated amortization through 12/31/2020.

ARIZONA PUBLIC SERVICE COMPANY
Pro Forma Adjustments to Original Cost Rate Base
Test Year Ended 6/30/19 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	UPDATED FOR REBUTTAL **Ocotillo Deferral** Total Co.
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation and Amortization	-
3.	Net Utility Plant in Service	-
4.	Less: Total Deductions	21,180
5.	Total Additions	85,577
6.	Total Rate Base	$ 64,397

Rebuttal adjustment to Test Year rate base to include actual amortization of the Ocotillo Modernization Project deferral through 9/30/2020 and estimated amortization through 12/31/2020.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 6/30/2019 - UPDATED FOR REBUTTAL
(Dollars in Thousands)

Line No.	Description	UPDATED FOR REBUTTAL **Ocotillo Deferral** Total Co.
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	9,507
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	9,507
15.	Operating Income Before Income Tax	(9,507)
16.	Interest Expense	-
17.	Taxable Income	(9,507)
18.	Current Income Tax Rate -	(2,353)
19.	Operating Income (line 15 minus line 18)	$ (7,154)

Rebuttal adjustment to Test Year operations to include actual amortization of the Ocotillo Modernization Project deferral through 9/30/2020 and estimated amortization through 12/31/2020.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 06/30/2019 - UPDATED FOR REBUTTAL
(Dollars in Thousands)

Line No.	Description		UPDATED FOR REBUTTAL Remove Out of Period and Miscellaneous Items Total Co.
	Electric Operating Revenues		
1.	Revenues from Base Rates	$	-
2.	Revenues from Surcharges		-
3.	Other Electric Revenues		-
4.	Total Electric Operating Revenues		-
5.	Electric Fuel and Purchased Power Costs		-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-
	Other Operating Expenses:		
7.	Operations Excluding Fuel Expense		-
8.	Maintenance		-
9.	Subtotal		-
10.	Depreciation and Amortization		-
11.	Amortization of Gain		-
12.	Administrative and General		(15,136)
13.	Other Taxes		-
14.	Total Other Operating Expense		(15,136)
15.	Operating Income Before Income Tax		15,136
16.	Interest Expense		-
17.	Taxable Income		15,136
18.	Current Income Tax Rate - 24.75%		3,746
19.	Operating Income (line 15 minus line 18)	$	11,390

Rebuttal adjustment to Test Year operations to remove out of period and miscellaneous items from the Test Year period.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 06/30/2019 - UPDATED FOR REBUTTAL
(Dollars in Thousands)

Line No.	Description	UPDATED FOR REBUTTAL Normalize Employee Benefits Total Co.
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	(2,750)
8.	Maintenance	-
9.	Subtotal	(2,750)
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total Other Operating Expense	(2,750)
15.	Operating Income Before Income Tax	2,750
16.	Interest Expense	-
17.	Taxable Income	2,750
18.	Current Income Tax Rate - 24.75%	681
19.	Operating Income (line 15 minus line 18)	$ 2,069

Rebuttal adjustment to Test Year operations to reflect averaging the actual 2019 and estimated 2020 pension and OPEB costs.

ARIZONA PUBLIC SERVICE COMPANY
Pro Forma Adjustments to Original Cost Rate Base
Test Year Ended 6/30/2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

			UPDATED FOR REBUTTAL RCND
		Excess Deferred Taxes	**Excess Deferred Taxes**
Line No.	Description	Total Co.	Total Co.
1.	Gross Utility Plant in Service	$ -	$ -
2.	Less: Accumulated Depreciation and Amortization	-	-
3.	Net Utility Plant in Service	-	-
4.	Less: Total Deductions	(190,188)	(349,882)
5.	Total Additions	-	-
6.	Total Rate Base	$ 190,188	$ 349,882

Rebuttal adjustment to Rate Base to reflect amortization of excess deferred taxes after the Test Year which have been refunded to customers through the TEAM pursuant to Decision No. 77464.

ARIZONA PUBLIC SERVICE COMPANY
Pro Forma Adjustments to Original Cost Rate Base
Test Year Ended 6/30/2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	UPDATED FOR REBUTTAL TEAM Balancing Accounts Total Co.
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation and Amortization	-
3.	Net Utility Plant in Service	-
4.	Less: Total Deductions	-
5.	Total Additions	6,556
6.	Total Rate Base	$ 6,556

Rebuttal adjustment to include balancing accounts associated with the TEAM I, TEAM II and a portion of TEAM III adjustor mechanisms as of September 30, 2020 in rate base.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 6/30/2019 - NEW FOR REBUTTAL
(Dollars in Thousands)

Line No.	Description		NEW FOR REBUTTAL TEAM Balancing Account Amortization Total Co.
	Electric Operating Revenues		
1.	Revenues from Base Rates		$ -
2.	Revenues from Surcharges		-
3.	Other Electric Revenues		-
4.	Total Electric Operating Revenues		-
5.	Electric Fuel and Purchased Power Costs		-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-
	Other Operating Expenses:		
7.	Operations Excluding Fuel Expense		-
8.	Maintenance		-
9.	Subtotal		-
10.	Depreciation and Amortization		656
11.	Amortization of Gain		-
12.	Administrative and General		-
13.	Other Taxes		-
14.	Total Other Operating Expense		656
15.	Operating Income Before Income Tax		(656)
16.	Interest Expense		-
17.	Taxable Income		(656)
18.	Current Income Tax Rate -	24.75%	(162)
19.	Operating Income (line 15 minus line 18)		$ (494)

Rebuttal adjustment to Test Year operations to reflect amortization of the Tax Expense Adjustment Mechanism Balancing Account from the rate effective date over ten years.

ARIZONA PUBLIC SERVICE COMPANY
Pro Forma Adjustments to Original Cost Rate Base
Test Year Ended 06/30/2019 - NEW FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	NEW FOR REBUTTAL Remove McMicken from the Test Year Total Co.
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation and Amortization	1,041
3.	Net Utility Plant in Service	(1,041)
4.	Less: Total Deductions	-
5.	Total Additions	-
6.	Total Rate Base	$ (1,041)

Rebuttal adjustment to remove amounts in accelerated depreciation related to cost of removal for the McMicken Battery Energy Storage Facility.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 06/30/2019 - NEW FOR REBUTTAL
(Dollars in Thousands)

Line No.	Description	NEW FOR REBUTTAL Remove McMicken Expenses from the Test Year Total Co.
	Electric Operating Revenues	
1.	Revenues from Base Rates	$ -
2.	Revenues from Surcharges	-
3.	Other Electric Revenues	-
4.	Total Electric Operating Revenues	-
5.	Electric Fuel and Purchased Power Costs	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-
	Other Operating Expenses:	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	(261)
11.	Amortization of Gain	-
12.	Administrative and General	(659)
13.	Other Taxes	(43)
14.	Total Other Operating Expense	(963)
15.	Operating Income Before Income Tax	963
16.	Interest Expense	(19)
17.	Taxable Income	982
18.	Current Income Tax Rate - 24.75%	243
19.	Operating Income (line 15 minus line 18)	$ 720

Rebuttal adjustment to Test Year operations to remove expenses related to the damaged and retired McMicken Battery Energy Storage Facility.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 6/30/2019 - UPDATED FOR REBUTTAL
(Dollars in Thousands)

Line No.	Description		UPDATED FOR REBUTTAL Include Interest Expense on Customer Deposits
	Electric Operating Revenues		
1.	Revenues from Base Rates	$	-
2.	Revenues from Surcharges		-
3.	Other Electric Revenues		-
4.	Total Electric Operating Revenues		-
5.	Electric Fuel and Purchased Power Costs		-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-
	Other Operating Expenses:		
7.	Operations Excluding Fuel Expense		1,270
8.	Maintenance		-
9.	Subtotal		1,270
10.	Depreciation and Amortization		-
11.	Amortization of Gain		-
12.	Administrative and General		-
13.	Other Taxes		-
14.	Total Other Operating Expense		1,270
15.	Operating Income Before Income Tax		(1,270)
16.	Interest Expense		-
17.	Taxable Income		(1,270)
18.	Current Income Tax Rate - 24.75%		(314)
19.	Operating Income (line 15 minus line 18)	$	(956)

Rebuttal adjustment to Test Year operations to update the operating income impact of interest on customer deposits using January 2020 interest rates.

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF ORIGINAL COST RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED 6/30/2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

		Original Cost						
		Total Company			ACC			
			UPDATED FOR REBUTTAL		UPDATED FOR REBUTTAL			
Line No.	Description	Unadjusted Test Year Ended 6/30/2019 (a)	Pro Forma (a)	Adjusted Test Year Ended 6/30/2019 (a)	Unadjusted Test Year Ended 6/30/2019 (a)	Pro Forma (a)	Adjusted Test Year Ended 6/30/2019 (a)	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	
1.	Gross utility plant in service	$ 20,668,805	$ 720,088	$ 21,388,893	$ 17,522,154	$ 703,966	$ 18,226,120	1.
2.	Less: Accumulated depreciation & amortization	7,267,041	526,210	7,793,251	6,323,170	514,999	6,838,169	2.
3.	Net utility plant in service	13,401,764	193,878	13,595,642	11,198,984	188,967	11,387,951	3.
	Deductions:							
4.	Deferred income taxes	1,908,074	100,708	2,008,782	1,903,465	100,610	2,004,075	4.
5.	Deferred investment tax credits (b)	197,749		197,749	196,800		196,800	5.
6.	Customer advances (b)	174,411		174,411	145,118		145,118	6.
7.	Customer deposits	81,423		81,423	81,423		81,423	7.
8.	Liabilities for pension benefits	305,207		305,207	280,175		280,175	8.
9.	Liability for asset retirements (b)	744,955		744,955	741,379		741,379	9.
10.	Other deferred credits	11,807		11,807	10,827		10,827	10.
11.	Coal mine reclamation (b)	197,443		197,443	196,575		196,575	11.
12.	Unrecognized tax benefits (b)	42,313		42,313	35,241		35,241	12.
13.	Operating lease liabilities (b)	111,553		111,553	79,892		79,892	13.
14.	Regulatory liabilities	2,008,573	(190,188)	1,818,385	1,988,202	(176,096)	1,812,107	14.
15.	Total deductions	5,783,508	(89,481)	5,694,028	5,659,096	(75,486)	5,583,610	15.
	Additions:							
16.	Regulatory assets	1,283,538	138,590	1,422,128	1,197,111	137,542	1,334,653	16.
17.	Other deferred debits	38,202		38,202	32,908		32,908	17.
18.	Nuclear Decommissioning trust (b)	950,448		950,448	945,886		945,886	18.
19.	Other special use funds (b)	241,558		241,558	240,398		240,398	19.
20.	Assets for other postretirement benefits (b)	52,611		52,611	48,296		48,296	20.
21.	Operating lease right-of-use assets (b)	174,320		174,320	135,941		135,941	21.
22.	Allowance for working capital (c)	384,155	(8,608)	375,547	361,745	(7,902)	353,843	22.
23.	Total additions	3,124,832	129,982	3,254,814	2,962,286	129,640	3,091,926	23.
24.	Total rate base	$ 10,743,088	$ 413,341	$ 11,156,429	$ 8,502,175	$ 394,093	$ 8,896,268 (d)	24.

Supporting Schedules:
(a) B-2
(b) E-1
(c) B-5

Recap Schedules:
(d) A-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF ORIGINAL COST RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED 6/30/2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

		RCND						
		Total Company UPDATED FOR REBUTTAL			ACC UPDATED FOR REBUTTAL			
Line No.	Description	Unadjusted Test Year Ended 6/30/2019 (a) (d) (A)	Pro Forma (a) (B)	Adjusted Test Year Ended 6/30/209 (a) (C)	Unadjusted Test Year Ended 6/30/2019 (a) (d) (D)	Pro Forma (a) (E)	Adjusted Test Year Ended 6/30/209 (a) (F)	Line No.
1.	Gross utility plant in service	$ 39,178,979	$ 720,088	$ 39,899,067	$ 33,214,311	$ 703,967	$ 33,918,278	1.
2.	Less: Accumulated depreciation & amortization	14,524,296	526,210	15,050,507	12,637,825	515,000	13,152,825	2.
3.	Net utility plant in service	24,654,683	193,878	24,848,561	20,576,485	188,967	20,765,453	3.
	Deductions:							
4.	Deferred income taxes	3,563,236	100,708	3,663,944	3,554,629	100,610	3,655,239	4.
5.	Deferred investment tax credits (b)	197,749		197,749	196,800		196,800	5.
6.	Customer advances (b)	174,411		174,411	145,118		145,118	6.
7.	Customer deposits	81,423		81,423	81,423		81,423	7.
8.	Liabilities for pension benefits	305,207		305,207	280,175		280,175	8.
9.	Liability for asset retirements (b)	744,955		744,955	741,379		741,379	9.
10.	Other deferred credits	11,807		11,807	10,827		10,827	10.
11.	Coal mine reclamation (b)	197,443		197,443	196,575		196,575	11.
12.	Unrecognized tax benefits (b)	42,313		42,313	35,241		35,241	12.
13.	Operating lease liabilities (b)	111,553		111,553	79,892		79,892	13.
14.	Regulatory liabilities	3,055,517	(349,882)	2,705,635	3,024,528	(323,956)	2,700,572	14.
15.	Total deductions	8,485,614	(249,174)	8,236,440	8,346,585	(223,346)	8,123,239	15.
	Additions:							
16.	Regulatory assets	1,283,538	138,590	1,422,128	1,197,111	137,542	1,334,653	16.
17.	Other deferred debits	38,202		38,202	32,908		32,908	17.
18.	Nuclear Decommissioning trust (b)	950,448		950,448	945,886		945,886	18.
19.	Other special use funds (b)	241,558		241,558	240,398		240,398	19.
20.	Assets for other postretirement benefits (b)	52,611		52,611	48,296		48,296	20.
21.	Operating lease right-of-use assets (b)	174,320		174,320	135,941		135,941	21.
22.	Allowance for working capital (c)	384,155	(8,608)	375,547	361,745	(7,902)	353,843	22.
23.	Total additions	3,124,832	129,982	3,254,814	2,962,286	129,640	3,091,926	23.
24.	Total rate base	$ 19,293,901	$ 573,034 (d)	$ 19,866,935 (d)	$ 15,192,186	$ 541,954 (d)	$ 15,734,140 (d) (e)	24.

Supporting Schedules:
(a) B-3
(b) E-1
(c) B-5
(d) B-4a

Recap Schedules:
(e) A-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

		(1) UPDATED FOR REBUTTAL Actual at End of Test Year 6/30/2019		(2) UPDATED FOR REBUTTAL Fossil Generation Post-Test Year Plant Additions		(3) UPDATED FOR REBUTTAL Nuclear Generation Post-Test Year Plant Additions	
Line No.	Description	(a) Total Co. (A)	(a) ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
1.	Gross Utility Plant in Service	$ 20,668,805	$ 17,522,154	$ 216,918	$ 215,877	$ 67,708	$ 67,383
2.	Less: Accumulated Depreciation & Amort.	7,267,041	6,323,170	201,688	200,720	17,283	17,200
3	Net Utility Plant in Service	13,401,764	11,198,984	15,230	15,157	50,425	50,183
4.	Less: Total Deductions	5,783,508	5,659,096	63,748	63,442	4,447	4,426
5.	Total Additions	3,124,832	2,962,286	-	-	-	-
6.	Total Rate Base	$ 10,743,088	$ 8,502,175	$ (48,518)	$ (48,285)	$ 45,978	$ 45,757

	(1)	(2)	(3)
PRO FORMA WITNESS:		BLANKENSHIP/TETLOW	BLANKENSHIP/TETLOW
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]		1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)

(1) Test Year Total Deductions and Total Additions are shown on Schedule B-1, page 1.

(2) Rebuttal adjustment to Test Year rate base to include actual depreciation, interest expense, property taxes and reduced income tax expense associated with Fossil Generation Post-Test Year Plant Additions.

(3) Rebuttal adjustment to Test Year rate base to include actual depreciation, interest expense, property taxes and reduced income tax expense associated with Nuclear Generation Post-Test Year Plant Additions.

Supporting Schedules
(a) B-1

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

		(4) UPDATED FOR REBUTTAL Distribution and IT/Facilities Post-Test Year Plant Additions		(5) UPDATED FOR REBUTTAL Technology Innovation Post-Test Year Plant Additions		(6) UPDATED FOR REBUTTAL Renewables Post-Test Year Plant Additions	
Line No.	Description	Total Co. (G)	ACC (H)	Total Co. (I)	ACC (J)	Total Co. (K)	ACC (L)
1.	Gross Utility Plant in Service	$ 418,060	$ 403,237	$ 14,187	$ 14,187	$ 17,048	$ 17,048
2.	Less: Accumulated Depreciation & Amort.	287,026	276,835	-	-	25,604	25,604
3	Net Utility Plant in Service	131,034	126,403	14,187	14,187	(8,556)	(8,556)
4.	Less: Total Deductions	2,284	2,506	(150)	(150)	2,485	2,485
5.	Total Additions	-	-	-	-	436	436
6.	Total Rate Base	$ 128,750	$ 123,897	$ 14,337	$ 14,337	$ (10,605)	$ (10,605)

	(4)	(5)	(6)
PRO FORMA WITNESS:	BLANKENSHIP/TETLOW	BLANKENSHIP/TETLOW	BLANKENSHIP/TETLOW
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Distribution functionalized on Distribution and IT/Facilities functionalized on Wages & Salaries	1. ACC Specific 2. Functionalized on Distribution	1. ACC Specific 2. Renewables functionalized on Demand Production (Retail DEMPROD1)

(4) Rebuttal adjustment to Test Year rate base to include actual depreciation, interest expense, property taxes and reduced income tax expense associated with Distribution and IT/Facilities Post-Test Year Plant Additions.

(5) Rebuttal adjustment to Test Year rate base to include actual depreciation, interest expense, property taxes and reduced income tax expense associated with Technology Innovation Post-Test Year Plant Additions.

(6) Rebuttal adjustment to Test Year rate base to include actual depreciation, interest expense, property taxes and reduced income tax expense associated with Renewables Post-Test Year Plant Additions.

Supporting Schedules
(a) B-1

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

		(7)		(8)		(9)	
		Cloud Computing		UPDATED FOR REBUTTAL Include West Phoenix Unit 4 Regulatory Disallowance		UPDATED FOR REBUTTAL Include Property Tax Deferral	
Line No.	Description	Total Co. (M)	ACC (N)	Total Co. (O)	ACC (P)	Total Co. (Q)	ACC (R)
1.	Gross Utility Plant in Service	$ -	$ -	$ (13,833)	$ (13,767) $ -	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	-	-	(6,432)	(6,401)	-	-
3	Net Utility Plant in Service	-	-	(7,401)	(7,365)	-	-
4.	Less: Total Deductions	-	-	(1,514)	(1,507)	(2,551)	(2,551)
5.	Total Additions	12,779	11,731	-	-	(10,308)	(10,308)
6.	Total Rate Base	$ 12,779	$ 11,731	$ (5,887)	$ (5,859)	$ (7,757)	$ (7,757)
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Functionalized on Wages & Salaries		1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)		1. ACC Specific 2. Distribution Property Tax functionalized on Distribution and Generation Property Tax functionalized on Demand Production (Retail DEMPROD1)	

(7) Adjustment to Test Year rate base to reflect the impacts of Cloud Computing in alignment with NARUC's Cloud Computing Resolution.

(8) Rebuttal adjustment to Test Year rate base to reflect amortization of regulatory disallowance of West Phoenix Unit 4 over the remaining life of the plant as required by previous ACC Decision Nos. 67744 and 69663.

(9) Rebuttal adjustment to Test Year rate base to annualize property taxes calculated using the actual 2019 composite tax rate.

Supporting Schedules
(a) B-1

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	(10) UPDATED FOR REBUTTAL Adjust Cash Working Capital for Cost of Service Total Co. (S)	(10) ACC (T)	(11) UPDATED FOR REBUTTAL Include Ocotillo Deferral Total Co. (U)	(11) ACC (V)	(12) UPDATED FOR REBUTTAL Include Four Corners SCR Deferral Total Co. (W)	(12) ACC (X)
1.	Gross Utility Plant in Service	$ -	$ -	$ -	$ -	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	-	-	-	-	-	-
3	Net Utility Plant in Service	-	-	-	-	-	-
4.	Less: Total Deductions	-	-	21,180	21,180	10,779	10,779
5.	Total Additions	(8,608)	(7,902)	85,577	85,577	43,550	43,550
6.	Total Rate Base	$ (8,608)	$ (7,902)	$ 64,397	$ 64,397	$ 32,771	$ 32,771
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Functionalized on Wages & Salaries		1. ACC Specific 2. Assigned to Production - Demand (Retail DEMPROD1)		1. ACC Specific 2. Assigned to Production - Demand (Retail DEMPROD1)	

(10) Rebuttal adjustment for updates to cash working capital rate base pro forma adjustment.

(11) Rebuttal adjustment to Test Year rate base to include actual amortization of the Ocotillo Modernization Project deferral through 9/30/2020 and estimated amortization through 12/31/2020. This pro forma is ACC specific.

(12) Rebuttal adjustment to Test Year rate base to include actual amortization of the Four Corners SCR deferral through 9/30/2020 and estimated amortization through 12/31/2020. This pro forma is ACC specific.

Supporting Schedules
(a) B-1

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	(13) UPDATED FOR REBUTTAL Excess Deferred Tax Total Co. (Y)	ACC (Z)	(14) NEW FOR REBUTTAL TEAM Balancing Accounts Total Co. (AA)	ACC (BB)	(15) NEW FOR REBUTTAL Remove McMicken Total Co. (CC)	ACC (DD)
1.	Gross Utility Plant in Service	$ -	$ -	$ -	$ -		
2.	Less: Accumulated Depreciation & Amort.	-	-	-	-	1,041	1,041
3	Net Utility Plant in Service	-	-	-	-	(1,041)	(1,041)
4.	Less: Total Deductions	(190,188)	(176,096)	-	-	-	-
5.	Total Additions	-	-	6,556	6,556	-	-
6.	Total Rate Base	$ 190,188	$ 176,096	$ 6,556	$ 6,556	$ (1,041)	$ (1,041)
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. ACC Specific 2. Assigned to Production - Demand (Retail DEMPROD1)		1. ACC Specific 2. Assigned to Production - Demand (Retail DEMPROD1)		1. ACC Specific 2. Functionalized on Distribution	

(13) Rebuttal adjustment to rate base to reflect amortization of excess deferred taxes associated with TEAM Phase III between the Test Year and the date proposed rates go into effect. Reflects ACC jurisdictional TEAM III amortization through 12/31/2020.

(14) Rebuttal adjustment to include balancing accounts associated with TEAM I, II, and a portion of TEAM III adjustment mechanisms as of 9/30/2020.

(15) Rebuttal adjustment to remove amounts in acceleerated depreciation related to cost of removal for the McMicken Battery Energy Storage Facility.

Supporting Schedules
(a) B-1

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

		(16) UPDATED FOR REBUTTAL Total Original Cost Rate Base Pro Forma Adjustments		(17) UPDATED FOR REBUTTAL Adjusted at End of Test Year 6/30/2019	
Line No.	Description	(b) Total Co. (EE)	(b) ACC (FF)	(b) Total Co. (GG)	(b) ACC (HH)
1.	Gross Utility Plant in Service	$ 720,088	$ 703,966	$ 21,388,893	$ 18,226,120
2.	Less: Accumulated Depreciation & Amort.	526,210	514,999	7,793,251	6,838,169
3	Net Utility Plant in Service	193,878	188,967	13,595,642	11,387,951
4.	Less: Total Deductions	(89,481)	(75,486)	5,694,028	5,583,610
5.	Total Additions	129,982	129,640	3,254,814	3,091,926
6.	Total Rate Base	$ 413,341	$ 394,093	$ 11,156,429	$ 8,896,268

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Supporting Schedules
(a) B-1

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT
TOTAL COMPANY
TEST YEAR ENDED JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

		Total Company			
Line No.	Description	Actual For The Test Year Ended 6/30/2019 (a) (A)	Proforma Adjustments (b) (B)	Test Year Results After Proforma Adjustments (c) (C)	Line No.
	Operating Revenues:				
1.	Revenues from Base Rates	$ 3,284,386	$ 6,862	$ 3,291,248	1.
2.	Revenues from Surcharges	128,995	(113,995)	15,000	2.
3.	Other Electric Revenues	216,871	(6,040)	210,831	3.
4.	Total	3,630,252	(113,173)	3,517,079	4.
	Operating expenses:				
5.	Fuel and purchased power	1,094,682	(105,795)	988,887	5.
6.	Operations and maintenance	909,326	(185,703)	723,623	6.
7.	Depreciation and amortization	584,838	106,201	691,039	7.
8.	Income taxes	123,315	9,121	132,436	8.
9.	Taxes other than income taxes	215,143	8,282	223,425	9.
10.	Total	2,927,304	(167,893)	2,759,411	10.
11.	Operating income	702,948	54,720	757,668	11.
	Other income (deductions):				
12.	Income taxes	6,467	-	6,467	12.
13.	Allowance for equity funds used during construction	43,927	-	43,927	13.
14.	Other income	34,998	-	34,998	14.
15.	Other expense	(22,582)	-	(22,582)	15.
16.	Total	62,810	-	62,810	16.
17.	Income before interest deductions	765,758	54,720	820,478	17.
	Interest deductions (income):				
18.	Interest charges	227,758	-	227,758	18.
19.	Allowance for borrowed funds used during construction	(23,293)	-	(23,293)	19.
20.	Total	204,465	-	204,465	20.
21.	Net income	$ 561,293	$ 54,720	$ 616,013	21.

Supporting Schedules:
(a) E-2
(b) C-2

Recap Schedules:
(c) A-2

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT
ACC JURISDICTION
TEST YEAR ENDED JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

		ACC Jurisdiction				
Line No.	Description	Actual For The Test Year Ended 6/30/2019 (A)	Proforma Adjustments (a) (B)	Test Year Results After Proforma Adjustments (C)		Line No.
	Operating Revenues:					
1.	Revenues from Base Rates	$ 3,273,579	$ 6,862	$ 3,280,441		1.
2.	Revenues from Surcharges	128,979	(113,979)	15,000		2.
3.	Other Electric Revenues	148,038	(6,040)	141,998		3.
4.	Total	3,550,597	(113,157)	3,437,440		4.
	Operating expenses:					
5.	Fuel and purchased power	1,083,172	(105,527)	977,645		5.
6.	Operations and maintenance	1,070,313	(182,380)	887,933		6.
7.	Depreciation and amortization	511,941	104,085	616,026		7.
8.	Income taxes	113,517	8,799	122,316		8.
9.	Taxes other than income taxes	177,260	7,533	184,793		9.
10.	Total	2,956,203	(167,490)	2,788,713		10.
11.	Operating income	594,393	54,333	648,726	(b)	11.
	Other income (deductions):					
12.	Income taxes	-	-			12.
13.	Allowance for equity funds used during construction	-	-			13.
14.	Other income	-	-			14.
15.	Other expense	-	-			15.
16.	Total	-				16.
17.	Income before interest deductions	594,393	54,333	648,726		17.
	Interest deductions (income):					
18.	Interest charges	-	-			18.
19.	Allowance for borrowed funds used during construction	-	-			19.
20.	Total	-	-	-		20.
21.	Net income	$ 594,393	$ 54,333	$ 648,726		21.

Supporting Schedules:
(a) C-2

Recap Schedules:
(b) A-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description		(1) UPDATED FOR REBUTTAL Fossil Generation Post-Test Year Plant Additions Total Co. (A)	ACC (B)	(2) UPDATED FOR REBUTTAL Nuclear Generation Post-Test Year Plant Additions Total Co. (C)	ACC (D)	(3) UPDATED FOR REBUTTAL Distribution and IT/Facilities Post-Test Year Plant Additions Total Co. (E)	ACC (F)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		-	-	-	-	-	-
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		-	-	-	-	-	-
10.	Depreciation and Amortization		9,551	9,505	210	209	21,794	20,532
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		1,442	1,435	453	451	8,018	7,738
14.	Total Other Operating Expense		10,993	10,940	663	660	29,812	28,270
15.	Operating Income Before Income Tax		(10,993)	(10,940)	(663)	(660)	(29,812)	(28,270)
16.	Interest Expense		283	282	938	933	2,437	2,284
17.	Taxable Income		(11,277)	(11,222)	(1,601)	(1,593)	(32,249)	(30,554)
18.	Current Income Tax Rate -	24.75%	(2,791)	(2,777)	(396)	(394)	(7,982)	(7,562)
19.	Operating Income (line 15 minus line 18)		$ (8,202)	(8,163)	$ (267)	$ (266)	$ (21,830)	$ (20,708)

	(1)	(2)	(3)
PRO FORMA WITNESS:	BLANKENSHIP/TETLOW	BLANKENSHIP/TETLOW	BLANKENSHIP/TETLOW
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	1. Jurisdictional 2. Distribution facilities functionalized on Distribution and IT/Facilities functionalized on Wages & Salaries

(1) Rebuttal adjustment to Test Year operations to include actual depreciation, interest expense, property taxes and reduced income tax expense associated with Fossil Generation Post-Test Year Plant Additions. Pro forma adjusted as shown on Rebuttal Schedule B-2, page 1, column 2.

(2) Rebuttal adjustment to Test Year operations to include actual depreciation, interest expense, property taxes and reduced income tax expense associated with Nuclear Generation Post-Test Year Plant Additions. Pro forma adjusted as shown on Rebuttal Schedule B-2, page 1, column 3.

(3) Rebuttal adjustment to Test Year operations to include actual depreciation, interest expense, property taxes and reduced income tax expense associated with Distribution and IT/Facilities Post-Test Year Plant Additions.
Pro forma adjusted as shown on Rebuttal Schedule B-2, page 2, column 4.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	(4) UPDATED FOR REBUTTAL Technology Innovation Post-Test Year Plant Additions		(5) UPDATED FOR REBUTTAL Renewables Post-Test Year Plant Additions		(6) UPDATED FOR REBUTTAL Base Fuel and Purchased Power	
		Total Co. (G)	ACC (H)	Total Co. (I)	ACC (J)	Total Co. (K)	ACC (L)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	(17,509)	(17,509)
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	17,509	17,509
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	1,419	1,419	506	506	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	265	265	67	67	-	-
14.	Total Other Operating Expense	1,684	1,684	573	573	-	-
15.	Operating Income Before Income Tax	(1,684)	(1,684)	(573)	(573)	17,509	17,509
16.	Interest Expense	264	264	(159)	(159)	-	-
17.	Taxable Income	(1,948)	(1,948)	(414)	(414)	17,509	17,509
18.	Current Income Tax Rate - 24.75%	(482)	(482)	(103)	(103)	4,333	4,333
19.	Operating Income (line 15 minus line 18)	$ (1,202)	$ (1,202)	$ (470)	$ (470)	$ 13,176	$ 13,176
	PRO FORMA WITNESS:	BLANKENSHIP/TETLOW		BLANKENSHIP/TETLOW		SNOOK	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. ACC Specific 2. Functionalized on Distribution		1. ACC Specific 2. Renewables functionalized on Demand Production [Retail DEMPROD1]		1. ACC Specific 2. Assigned to Production - Energy (Retail Only ENERGY2)	

(4) Rebuttal adjustment to Test Year operations to include actual depreciation, interest expense, property taxes and reduced income tax expense associated with Technology Innovation Post-Test Year Plant Additions. Pro forma adjusted as shown on Rebuttal Schedule B-2, page 2, column 5.

(5) Rebuttal adjustment to Test Year operations to include actual depreciation, interest expense, property taxes and reduced income tax expense associated with Renewables Post-Test Year Plant Additions. Pro forma adjusted as shown on Rebuttal Schedule B-2, page 2, column 6.

(6) Rebuttal adjustment to Test Year operations to include Staff recommended 2019 base fuel and purchased power ¢/kWh costs at adjusted Test Year consumption.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	(7) Test Year PSA Revenue and Deferred Fuel Amortization Total Co. (M)	ACC (N)	(8) Test Year Retail Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals Total Co. (O)	ACC (P)	(9) Test Year Deferred Chemical Expense Total Co. (Q)	ACC (R)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	(89,285)	(89,040)	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	(89,285)	(89,040)	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	(90,598)	(90,349)	40,435	40,435	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	1,313	1,309	(40,435)	(40,435)	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	1,313	1,309	-	-	-	-
8.	Maintenance	-	-	-	-	3,194	3,194
9.	Subtotal	1,313	1,309	-	-	3,194	3,194
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	1,313	1,309	-	-	3,194	3,194
15.	Operating Income Before Income Tax	-	-	(40,435)	(40,435)	(3,194)	(3,194)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	-	-	(40,435)	(40,435)	(3,194)	(3,194)
18.	Current Income Tax Rate - 24.75%	-	-	(10,008)	(10,008)	(791)	(791)
19.	Operating Income (line 15 minus line 18)	$ -	$ -	$ (30,427)	$ (30,427)	$ (2,403)	$ (2,403)
	PRO FORMA WITNESS:	SNOOK		SNOOK		SNOOK	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Revenues and Expenses are class specific		1. ACC Specific 2. Assigned to Production - Energy (Retail Only ENERGY2_XAG1)		1. ACC Specific 2. Assigned to Production - Energy (Retail Only ENERGY2_XAG1)	

(7) Adjustment to Test Year retail operating revenues and fuel and purchased power expense to remove retail PSA revenue and amortization of deferred fuel related to prior periods.

(8) Adjustment to Test Year retail fuel and purchased power costs to remove retail PSA deferred fuel and mark-to-market accruals.

(9) Adjustment to Test Year operation and maintenance costs to remove retail PSA deferred chemical expenses.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	(10) Normalize Weather Conditions Total Co. (S)	(10) ACC (T)	(11) Annualize Customer Levels Total Co. (U)	(11) ACC (V)	(12) Schedule 1 Fees Total Co. (W)	(12) ACC (X)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ (6,049)	$ (6,049)	$ 12,911	$ 12,911	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	(6,040)	(6,040)
4.	Total Electric Operating Revenues	(6,049)	(6,049)	12,911	12,911	(6,040)	(6,040)
5.	Electric Fuel and Purchased Power Costs	(1,812)	(1,812)	3,854	3,854	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(4,237)	(4,237)	9,057	9,057	(6,040)	(6,040)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	-	-	-	-	-	-
15.	Operating Income Before Income Tax	(4,237)	(4,237)	9,057	9,057	(6,040)	(6,040)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	(4,237)	(4,237)	9,057	9,057	(6,040)	(6,040)
18.	Current Income Tax Rate - 24.75%	(1,049)	(1,049)	2,242	2,242	(1,495)	(1,495)
19.	Operating Income (line 15 minus line 18)	$ (3,188)	$ (3,188)	$ 6,815	$ 6,815	$ (4,545)	$ (4,545)
	PRO FORMA WITNESS:	SNOOK		SNOOK		HOBBICK	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. ACC Specific 2. Revenues and Expenses are class specific		1. ACC Specific 2. Revenues and Expenses are class specific		1. ACC Specific 2. Functionalized on Customer Accounts (CUSTNUM_A)	

(10) Adjustment to Test Year operating revenues to reflect normal weather conditions for the ten years ended 6/30/2019.

(11) Adjustment to Test Year operating revenues to reflect the annualization of customer levels at 6/30/2019.

(12) Adjustment to Test Year operations to account for additional adjustments related to disconnect policy. Additional adjustments to Revenues reflecting policies changes to multiple fees collected.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	(13) Uncollectible Bad Debt Total Co. (Y)	(13) Uncollectible Bad Debt ACC (Z)	(14) UPDATED FOR REBUTTAL Crisis Bill Total Co. (AA)	(14) UPDATED FOR REBUTTAL Crisis Bill ACC (AB)	(15) Customer Affordability Total Co. (AC)	(15) Customer Affordability ACC (AD)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	-	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	6,427	6,427	1,250	1,250	(17,782)	(17,782)
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	6,427	6,427	1,250	1,250	(17,782)	(17,782)
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	6,427	6,427	1,250	1,250	(17,782)	(17,782)
15.	Operating Income Before Income Tax	(6,427)	(6,427)	(1,250)	(1,250)	17,782	17,782
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	(6,427)	(6,427)	(1,250)	(1,250)	17,782	17,782
18.	Current Income Tax Rate - 24.75%	(1,591)	(1,591)	(309)	(309)	4,401	4,401
19.	Operating Income (line 15 minus line 18)	$ (4,836)	$ (4,836)	$ (941)	$ (941)	$ 13,381	$ 13,381
	PRO FORMA WITNESS:	HOBBICK		HOBBICK		LOCKWOOD	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. ACC Specific 2. Functionalized on Customer Accounts (CUSTNUM_A)		1. ACC Specific 2. Assigned to System Benefits (Retail ERGSYSBEN)		1. ACC Specific 2. Functionalized on Wages & Salaries less Transmission	

(13) Adjustment to Test Year operations to account for expected increases in write-offs due to disconnect policy.

(14) Rebuttal adjustment correcting an inadvertent error where crisis bill assistance was shown as revenue but should have been an expense. However, operating income impact was correct; therefore no revised pro forma has been developed.

(15) Adjustment to include forecasted impacts to 2020 O&M as a result of the Customer Affordability program.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

		(16)		(17)		(18)	
		Active Union Medical Trust (VEBA)		Fire Mitigation		Remove Test Year Regulatory Assessment	
Line No.	Description	Total Co. (AE)	ACC (AF)	Total Co. (AG)	ACC (AH)	Total Co. (AI)	ACC (AJ)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	(6,769)	(6,769)
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	(6,769)	(6,769)
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	(6,769)	(6,769)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(3,643)	(3,344)	3,298	3,298	(6,769)	(6,769)
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	(3,643)	(3,344)	3,298	3,298	(6,769)	(6,769)
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(3,643)	(3,344)	3,298	3,298	(6,769)	(6,769)
15.	Operating Income Before Income Tax	3,643	3,344	(3,298)	(3,298)	-	-
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	3,643	3,344	(3,298)	(3,298)	-	-
18.	Current Income Tax Rate - 24.75%	902	828	(816)	(816)	-	-
19.	Operating Income (line 15 minus line 18)	$ 2,741	$ 2,516	$ (2,482)	$ (2,482)	$ -	$ -
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP/TETLOW		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Functionalized on Wages & Salaries		1. ACC Specific 2. Functionalized on Distribution		1. ACC Specific 2. Revenues are class specific and expenses are functionalized on Distribution of W&S	

(16) Adjustment to Test Year operations to include interest income and realized gain on investments in active union medical trust.

(17) Adjustment to represent the forecasted impacts to 2020 O&M as a result of increases to the distribution Fire Mitigation program.

(18) Adjustment to Test Year operations to remove the Regulatory Assessment surcharges from operating revenues and expenses.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	(19) Remove Test Year Transmission Cost Adjustor (TCA) Total Co. (AK)	(19) ACC (AL)	(20) Remove Test Year Lost Fixed Cost Recovery Mechanism (LFCR) Total Co. (AM)	(20) ACC (AN)	(21) Remove and Transfer Test Year Environmental Improvement Surcharge (EIS) Total Co. (AO)	(21) ACC (AP)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	(33,311)	(33,369)	(39,792)	(39,792)	(3,898)	(3,888)
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	(33,311)	(33,369)	(39,792)	(39,792)	(3,898)	(3,888)
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(33,311)	(33,369)	(39,792)	(39,792)	(3,898)	(3,888)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(33,311)	(33,369)	(39,792)	(39,792)	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	(33,311)	(33,369)	(39,792)	(39,792)	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(33,311)	(33,369)	(39,792)	(39,792)	-	-
15.	Operating Income Before Income Tax	-	-	-	-	(3,898)	(3,888)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	-	-	-	-	(3,898)	(3,888)
18.	Current Income Tax Rate - 24.75%	-	-	-	-	(965)	(962)
19.	Operating Income (line 15 minus line 18)	$ -	$ -	$ -	$ -	$ (2,933)	$ (2,926)

	(19)	(20)	(21)
PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Revenues are class specific	1. ACC Specific 2. Revenues are class specific	1. Jurisdictional 2. Revenues are class specific

(19) Adjustment to Test Year operations to remove the Transmission Cost Adjustor from operating revenues and expenses.

(20) Adjustment to Test Year operations to remove the LFCR mechanism from operating revenues.

(21) Adjustment to Test Year operations to remove the EIS from operating revenues.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	(22) Remove Test Year Demand Side Management Adjustment Clause (DSMAC) Revenue & Expense		(23) Remove Test Year and Transfer a Portion of Renewable Energy Adjustment Clause (REAC) Revenue and Expense		(24) Remove and Transfer Test Year Tax Expense Adjustor Mechanism (TEAM) Revenue	
		Total Co. (AQ)	ACC (AR)	Total Co. (AS)	ACC (AT)	Total Co. (AU)	ACC (AV)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	(26,717)	(26,689)	(72,697)	(72,670)	143,475	143,238
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	(26,717)	(26,689)	(72,697)	(72,670)	143,475	143,238
5.	Electric Fuel and Purchased Power Costs	-	-	(38,930)	(38,916)	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(26,717)	(26,689)	(33,767)	(33,754)	143,475	143,238
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(26,717)	(26,689)	(33,445)	(33,433)	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	(26,717)	(26,689)	(33,445)	(33,433)		
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(26,717)	(26,689)	(33,445)	(33,433)	-	-
15.	Operating Income Before Income Tax	-	-	(322)	(321)	143,475	143,238
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	-	-	(322)	(321)	143,475	143,238
18.	Current Income Tax Rate - 24.75%	-	-	(80)	(80)	35,510	35,451
19.	Operating Income (line 15 minus line 18)	$ -	$ -	$ (242)	$ (241)	$ 107,965	$ 107,787
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Revenues and Expenses are class specific		1. Jurisdictional 2. Revenues and Expenses are class specific		1. Jurisdictional 2. Revenues and Expenses are class specific	

(22) Adjustment to Test Year operations to remove the DSMAC from operating revenues and expenses.

(23) Adjustment to Test Year operations to remove the REAC from operating revenues and transfer a portion of the expenses related to APS Solar Communities (formerly known as AZ Sun II) to base rates.

(24) Adjustment to Test Year operations to remove and transfer the TEAM adjustor from operating revenues.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description		(25) UPDATED FOR REBUTTAL Four Corners SCR Deferral Amortization Total Co. (AW)	(25) ACC (AX)	(26) UPDATED FOR REBUTTAL Ocotillo Modernization Project Deferral Amortization Total Co. (AY)	(26) ACC (AZ)	(27) Four Corners Inventory Total Co. (BA)	(27) ACC (BB)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		-	-	-	-	-	-
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		-	-	-	-	-	-
10.	Depreciation and Amortization		8,147	8,147	9,507	9,507	1,045	1,040
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		-	-	-	-	-	-
14.	Total Other Operating Expense		8,147	8,147	9,507	9,507	1,045	1,040
15.	Operating Income Before Income Tax		(8,147)	(8,147)	(9,507)	(9,507)	(1,045)	(1,040)
16.	Interest Expense		-	-	-	-	-	-
17.	Taxable Income		(8,147)	(8,147)	(9,507)	(9,507)	(1,045)	(1,040)
18.	Current Income Tax Rate -	24.75%	(2,016)	(2,016)	(2,353)	(2,353)	(259)	(258)
19.	Operating Income (line 15 minus line 18)		$ (6,131)	$ (6,131)	$ (7,154)	$ (7,154)	$ (786)	$ (782)
	PRO FORMA WITNESS:		BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]		1. ACC Specific 2. Assigned to Production - Demand (DEMPROD1)		1. ACC Specific 2. Assigned to Production - Demand (DEMPROD1)		1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	

(25) Rebuttal adjustment to Test Year operations to include actual amortization of the Four Corners SCR deferral through 9/30/2020 and estimated amortization through 12/31/2020. This pro forma is ACC specific.

(26) Rebuttal adjustment to Test Year operations to include actual amortization of the Ocotillo Modernization Project deferral through 9/30/2020 and estimated amortization through 12/31/2020. This pro forma is ACC specific.

(27) Adjustment to Test Year operations to reflect Four Corners inventory cost recovery.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description		(28) Cholla Inventory Total Co. (BC)	(28) Cholla Inventory ACC (BD)	(29) UPDATED FOR REBUTTAL West Phoenix Unit 4 Regulatory Disallowance Total Co. (BE)	(29) ACC (BF)	(30) Remove Navajo Power Plant Costs Total Co. (BE)	(30) ACC (BF)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		-	-	-	-	(10,567)	(10,522)
8.	Maintenance		-	-	-	-	(6,446)	(6,418)
9.	Subtotal		-	-	-	-	(17,014)	(16,940)
10.	Depreciation and Amortization		1,523	1,516	(329)	(327)	-	-
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	541	539
13.	Other Taxes		-	-	-	-	-	-
14.	Total Other Operating Expense		1,523	1,516	(329)	(327)	(16,473)	(16,401)
15.	Operating Income Before Income Tax		(1,523)	(1,516)	329	327	16,473	16,401
16.	Interest Expense		-	-	(110)	(109)	-	-
17.	Taxable Income		(1,523)	(1,516)	439	437	16,473	16,401
18.	Current Income Tax Rate -	24.75%	(377)	(375)	109	108	4,077	4,059
19.	Operating Income (line 15 minus line 18)		$ (1,146)	$ (1,141)	$ 220	$ 219	$ 12,396	$ 12,342

	(28)	(29)	(30)
PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	1. Jurisdictional 2. Assigned to Production - Energy (ENERGY1)

(28) Adjustment to Test Year operations to reflect Cholla inventory cost recovery.

(29) Rebuttal adjustment to Test Year operations to reflect amortization of regulatory disallowance of West Phoenix Unit 4 over the remaining life of the plant as required by previous ACC Decision Nos. 67744 and 69663. Pro forma adjusted as shown on Schedule B-2, page 3, column 8. The correction does not show due to rounding to thousands.

(30) Adjustment to Test Year operations to remove Navajo O&M and A&G costs as a result of the closure of Navajo Power Plant.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	(31) Ocotillo O&M Normalization Total Co. (BG)	(31) ACC (BH)	(32) UPDATED FOR REBUTTAL Include Interest Expense on Customer Deposits Total Co. (BI)	(32) ACC (BJ)	(33) UPDATED FOR REBUTTAL Adjust Depreciation Expense - 2019 Depreciation Rate Study Total Co. (BK)	(33) ACC (BL)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	5,643	5,618	1,270	1,270	-	-
8.	Maintenance	1,104	1,099	-	-	-	-
9.	Subtotal	6,747	6,717	1,270	1,270	-	-
10.	Depreciation and Amortization	-	-	-	-	62,940	62,097
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	(16)	(16)	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	6,730	6,701	1,270	1,270	62,940	62,097
15.	Operating Income Before Income Tax	(6,730)	(6,701)	(1,270)	(1,270)	(62,940)	(62,097)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	(6,730)	(6,701)	(1,270)	(1,270)	(62,940)	(62,097)
18.	Current Income Tax Rate - 24.75%	(1,666)	(1,659)	(314)	(314)	(15,578)	(15,369)
19.	Operating Income (line 15 minus line 18)	$ (5,064)	$ (5,042)	$ (956)	$ (956)	$ (47,362)	$ (46,728)

	(31)	(32)	(33)
PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Assigned to Production - Energy (ENERGY1)	1. ACC Specific 2. Assigned to Customer Accounts (CUSTDEP)	1. Jurisdictional 2. Assigned to PT&D, General and Intangible functionalized on Wages & Salaries

(31) Adjust Test Year to reflect the continuing operations of the Ocotillo Power Plant with the retirement of 2 steam units and the addition of the new units.

(32) Rebuttal adjustment to Test Year Operations to update the operating income impact of interest on customer deposits using January 2020 interest rates.

(33) Rebuttal adjustment to Test Year operations to reflect updated depreciation study rates based on revisions to the 2019 Depreciation Rate Study.

Supporting Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	(34) Annualize Payroll Expense Total Co. (BM)	(34) ACC (BN)	(35) UPDATED FOR REBUTTAL Normalize Employee Benefits Total Co. (BO)	(35) ACC (BP)	(36) Remove Supplemental Excess Benefit Retirement Plan Expense (SERP) Total Co. (BQ)	(36) ACC (BR)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(410)	(376)	(2,750)	(2,524)	(8,429)	(7,738)
8.	Maintenance	(84)	(77)	-	-	-	-
9.	Subtotal	(494)	(453)	(2,750)	(2,524)	(8,429)	(7,738)
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(494)	(453)	(2,750)	(2,524)	(8,429)	(7,738)
15.	Operating Income Before Income Tax	494	453	2,750	2,524	8,429	7,738
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	494	453	2,750	2,524	8,429	7,738
18.	Current Income Tax Rate - 24.75%	122	112	681	625	2,086	1,915
19.	Operating Income (line 15 minus line 18)	$ 372	$ 341	$ 2,069	$ 1,899	$ 6,343	$ 5,823
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Functionalized on Wages & Salaries		1. Jurisdictional 2. Functionalized on Wages & Salaries		1. Jurisdictional 2. Functionalized on Wages & Salaries	

(34) Adjustment to Test Year operations to reflect the annualization of payroll, payroll tax and non-retirement benefit expenses to March 2019 employee levels for performance review and March 2020 Union employee levels.

(35) Rebuttal adjustment to Test Year operations to reflect averaging the actual 2019 and estimated 2020 pension and OPEB costs.

(36) Adjustment to Test Year operations to remove Supplemental Excess Benefit Retirement Plan Expense (SERP).

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	(37) Remove Stock Compensation Total Co. (BS)	(37) Remove Stock Compensation ACC (BT)	(38) Normalize Cash Incentive Total Co. (BU)	(38) Normalize Cash Incentive ACC (BV)	(39) Normalize Income Tax Expense/Interest Synchronization Total Co. (BW)	(39) Normalize Income Tax Expense/Interest Synchronization ACC (BX)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(15,882)	(14,580)	4,153	3,812	-	-
8.	Maintenance	-	-	126	116	-	-
9.	Subtotal	(15,882)	(14,580)	4,279	3,928	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	1,327	1,218	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(15,882)	(14,580)	5,606	5,146	-	-
15.	Operating Income Before Income Tax	15,882	14,580	(5,606)	(5,146)	-	-
16.	Interest Expense	-	-	-	-	23,665	24,404
17.	Taxable Income	15,882	14,580	(5,606)	(5,146)	(23,665)	(24,404)
18.	Current Income Tax Rate - 24.75%	3,931	3,608	(1,388)	(1,274)	(5,857)	(6,040)
19.	Operating Income (line 15 minus line 18)	$ 11,951	$ 10,972	$ (4,218)	$ (3,872)	$ 5,857	$ 6,040

	(37)	(38)	(39)
PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Functionalized on Wages & Salaries	1. Jurisdictional 2. Functionalized on Wages & Salaries	1. Jurisdictional 2. Calculated as the weighted average of "Other Tax Items"

(37) Adjustment to Test Year operations to remove stock compensation expense.

(38) Adjustment to Test Year operations to normalize the cash incentive program over a 3 year period.

(39) Adjustment to Test Year operations for top down income tax true-ups consistent with Decision Nos. 69663, 71448, 73183, and 76295 using the 6/30/2019 rate base and cost of long-term debt. Tax true-ups are reflected as interest in this adjustment.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description		(40) UPDATED FOR REBUTTAL Annualize Property Tax Expense Total Co. (BY)	ACC (BZ)	(41) UPDATED FOR REBUTTAL Amortize Property Tax Deferral Total Co. (CA)	ACC (CB)	(42) West Phoenix Removal Costs Total Co. (CC)	ACC (CD)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		-	-	-	-	-	-
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		-	-	-	-	-	-
10.	Depreciation and Amortization		-	-	-	-	998	993
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		2,750	2,290	(4,671)	(4,671)	-	-
14.	Total Other Operating Expense		2,750	2,290	(4,671)	(4,671)	998	993
15.	Operating Income Before Income Tax		(2,750)	(2,290)	4,671	4,671	(998)	(993)
16.	Interest Expense		-	-	(151)	(151)	-	-
17.	Taxable Income		(2,750)	(2,290)	4,822	4,822	(998)	(993)
18.	Current Income Tax Rate -	24.75%	(681)	(567)	1,193	1,193	(247)	(246)
19.	Operating Income (line 15 minus line 18)		$ (2,069)	$ (1,723)	$ 3,478	$ 3,478	$ (751)	$ (747)

	(40)	(41)	(42)
PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Functionalized on P T & D	ACC Specific 2. Distribution Property Tax functionalized on Distribution and Generation Property Tax functionalized on Demand Production (Retail DEMPROD1)	1. Jurisdictional 2. Assigned to Production Demand (DEMPROD1)

(40) Rebuttal adjustment to Test Year operations to annualize property taxes calculated using the actual 2019 composite tax rate.

(41) Rebuttal adjustment to amortize the property tax deferral as authorized in Decision No. 76295 over 3 years rather than 10 years. Pro forma adjusted as shown on Schedule B-2, page 3, column 9.

(42) Adjustment to include additional costs of removal related to the decommissioning of West Phoenix Steam Units 4, 5 & 6.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	(43) Annualize Four Corners Power Plant Coal Reclamation Costs Total Co. (CE)	(43) ACC (CF)	(44) Annualize Navajo Power Plant Coal Reclamation Costs Total Co. (CG)	(44) ACC (CH)	(45) UPDATED FOR REBUTTAL Adjust Cash Working Capital for Cost of Service Pro Formas Total Co. (CI)	(45) ACC (CJ)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	(3,145)	(3,131)	1,910	1,902	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	3,145	3,131	(1,910)	(1,902)	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	-	-	-	-	-	-
15.	Operating Income Before Income Tax	3,145	3,131	(1,910)	(1,902)	-	-
16.	Interest Expense	-	-	-	-	(160)	(147)
17.	Taxable Income	3,145	3,131	(1,910)	(1,902)	160	147
18.	Current Income Tax Rate - 24.75%	778	775	(473)	(471)	40	36
19.	Operating Income (line 15 minus line 18)	$ 2,367	$ 2,356	$ (1,437)	$ (1,431)	$ (40)	$ (36)
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Assigned to System Benefits (ERGSYSBEN)		1. Jurisdictional 2. Assigned to System Benefits (ERGSYSBEN)		1. Jurisdictional 2. Functionalized on Wages & Salaries	

(43) Adjustment to Test Year operations to reflect most recent Four Corners Power Plant coal reclamation study.

(44) Adjustment to Test Year operations to reflect the most recent Navajo Power Plant coal reclamation study.

(45) Rebuttal adjustment to Test Year interest expense for updates to cash working capital rate base pro forma adjustment.
Pro forma adjusted as shown on Schedule B-2, page 4, column 10.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	(46) Normalize Advertising Total Co. (CK)	(46) ACC (CL)	(47) Normalize Nuclear Maintenance Expense Total Co. (CM)	(47) ACC (CN)	(48) Normalize Fossil Maintenance Expense Total Co. (CO)	(48) ACC (CP)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(2,264)	(2,264)	-	-	-	-
8.	Maintenance	-	-	1,386	1,380	5,882	5,856
9.	Subtotal	(2,264)	(2,264)	1,386	1,380	5,882	5,856
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(2,264)	(2,264)	1,386	1,380	5,882	5,856
15.	Operating Income Before Income Tax	2,264	2,264	(1,386)	(1,380)	(5,882)	(5,856)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	2,264	2,264	(1,386)	(1,380)	(5,882)	(5,856)
18.	Current Income Tax Rate - 24.75%	560	560	(343)	(342)	(1,456)	(1,449)
19.	Operating Income (line 15 minus line 18)	$ 1,704	$ 1,704	$ (1,043)	$ (1,038)	$ (4,426)	$ (4,407)

	(46)	(47)	(48)
PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. ACC Specific 2. Functionalized on Wages & Salaries less Transmission	1. Jurisdictional 2. Assigned to Production - Energy (ENERGY1)	1. Jurisdictional 2. Assigned to Production - Energy (ENERGY1)

(46) Adjustment to Test Year operations to normalize advertising expense over a 3 year period.

(47) Adjustment to Test Year operations to normalize nuclear production maintenance expense over a 3 year period.

(48) Adjustment to Test Year operations to normalize fossil production maintenance expense over a 6 year period.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description		(49) Adjust Sundance Maintenance Total Co. (CQ)	(49) ACC (CR)	(50) UPDATED FOR REBUTTAL Remove Out of Period and Miscellaneous Items Total Co. (CS)	(50) ACC (CT)	(51) Cholla Unit 2 Regulatory Asset Amortization Total Co. (CU)	(51) ACC (CV)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges			-	-	-	-	-
3.	Other Electric Revenues			-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs			-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		-	-	-	-	-	-
8.	Maintenance		1,487	1,481	-	-	-	-
9.	Subtotal		1,487	1,481	-	-	-	-
10.	Depreciation and Amortization			-	-	-	(11,504)	(11,454)
11.	Amortization of Gain			-	-	-	-	-
12.	Administrative and General			-	(15,136)	(13,894)	-	-
13.	Other Taxes			-	-	-	-	-
14.	Total Other Operating Expense		1,487	1,481	(15,136)	(13,894)	(11,504)	(11,454)
15.	Operating Income Before Income Tax		(1,487)	(1,481)	15,136	13,894	11,504	11,454
16.	Interest Expense			-	-	-	-	-
17.	Taxable Income		(1,487)	(1,481)	15,136	13,894	11,504	11,454
18.	Current Income Tax Rate -	24.75%	(368)	(366)	3,746	3,439	2,847	2,835
19.	Operating Income (line 15 minus line 18)		$ (1,119)	$ (1,115)	$ 11,390	$ 10,455	$ 8,657	$ 8,619
	PRO FORMA WITNESS:		BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]		1. Jurisdictional 2. Assigned to Production - Energy (ENERGY1)		1. Jurisdictional 2. Functionalized on Wages & Salaries		1. Jurisdictional 2. Assigned to System Benefits (ERGSYSBEN)	

(49) Adjustment to Test Year operations to annualize the accrual of Sundance maintenance costs as authorized in Decision No. 69663.

(50) Rebuttal adjustment to Test Year operations to remove out of period and miscellaneous items from the Test Year period.

(51) Adjust test year to amortize Cholla Unit 2 Regulatory Asset over the remaining plant life instead of the accelerated method approved in Decision No. 76295.

Supporting Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

Line No.	Description	(52) NEW FOR REBUTTAL Adjust for Test Year AG-X Revenue recovered in the PSA		(53) NEW FOR REBUTTAL TEAM Balancing Account		(54) NEW FOR REBUTTAL Remove McMicken	
		Total Co. (CW)	ACC (CX)	Total Co. (CY)	ACC (CZ)	Total Co. (DA)	ACC (DB)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	15,000	15,000	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	15,000	15,000	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	15,000	15,000	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	-	-	656	656	(261)	(261)
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	(659)	(659)
13.	Other Taxes	-	-	-	-	(43)	(43)
14.	Total Other Operating Expense	-	-	656	656	(963)	(963)
15.	Operating Income Before Income Tax	15,000	15,000	(656)	(656)	963	963
16.	Interest Expense	-	-	-	-	(19)	(19)
17.	Taxable Income	15,000	15,000	(656)	(656)	982	982
18.	Current Income Tax Rate - 24.75%	3,713	3,713	(162)	(162)	243	243
19.	Operating Income (line 15 minus line 18)	$ 11,287	$ 11,287	$ (494)	$ (494)	$ 720	$ 720
	PRO FORMA WITNESS:	SNOOK		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. ACC Specific 2. Revenues and Expenses are class specific		1. ACC Specific 2. Assigned to Production Demand (DEMPROD1)		1. ACC Specific 2. Functionalized on Distribution	

(52) Rebuttal adjustment to Test Year operations to offset AG-X revenue recovered through the PSA surcharge mechanism.

(53) Rebuttal adjustment to Test Year operations to reflect amortization of the Tax Expense Adjustment Mechanism Balancing Account from the rate effective date over ten years.

(54) Rebuttal adjustment to Test Year operations to remove expenses related to the damaged and retired McMicken Battery Energy Storage Facility.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019 - UPDATED FOR REBUTTAL
(Thousands of Dollars)

(55)

Line No.	Description		UPDATED FOR REBUTTAL Total Income Statement Adjustments (a) Total Co. (DC)	(a) ACC (DD)
	Electric Operating Revenues			
1.	Revenues from Base Rates		$ 6,862	$ 6,862
2.	Revenues from Surcharges		(113,995)	(113,979)
3.	Other Electric Revenues		(6,040)	(6,040)
4.	Total Electric Operating Revenues		(113,173)	(113,157)
5.	Electric Fuel and Purchased Power Costs		(105,795)	(105,527)
6.	Oper Rev Less Fuel & Purch Pwr Costs		(7,378)	(7,630)
	Other Operating Expenses:			
7.	Operations Excluding Fuel Expense		(178,409)	(176,198)
8.	Maintenance		6,649	6,630
9.	Subtotal		(171,760)	(169,568)
10.	Depreciation and Amortization		106,201	104,085
11.	Amortization of Gain		-	-
12.	Administrative and General		(13,943)	(12,812)
13.	Other Taxes		8,282	7,533
14.	Total Other Operating Expense		(71,220)	(70,762)
15.	Operating Income Before Income Tax		63,842	63,132
16.	Interest Expense		26,988	27,582
17.	Taxable Income		36,854	35,550
18.	Current Income Tax Rate -	24.75%	9,121	8,799
19.	Operating Income (line 15 minus line 18)		$ 54,720	$ 54,333

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF GROSS REVENUE CONVERSION FACTOR
TOTAL COMPANY
TEST YEAR ENDED JUNE 30, 2019 - UPDATED FOR REBUTTAL

Line No.	Description	2019 Percentage of Incremental Gross Revenues	*Line No.*
1.	Gross Revenue	100%	*1.*
2.	Less uncollectible revenue	0.41%	*2.*
3.	Taxable revenue as a percent	99.59%	*3.*
4.	Federal Income Taxes	20.91%	*4.*
5.	State Income Taxes Net of Federal Tax Benefit	3.75%	*5.*
6.	Total Tax Percentage	24.66%	*6.*
7.	Taxable Revenue - Tax Percentage	74.93%	*7.*
8.	1/Operating Income % = Gross Revenue Conversion Factor (a)	1.3346	*8.*

Supporting Schedules:
N/A

Recap Schedules:
(a) A-1

Note: There may be variances in displayed values due to rounding.

ATTACHMENT 5

REBUTTAL TESTIMONY OF JACOB TETLOW

On Behalf of Arizona Public Service Company

Docket No. E-01345A-19-0236

November 6, 2020

Table of Contents

Attachments

REBUTTAL TESTIMONY OF JACOB TETLOW
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-19-0236)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Jacob Tetlow. I am Senior Vice President of Non-Nuclear Operations at Arizona Public Service Company (APS or Company), and my business address is 400 N. 5th Street in Phoenix, Arizona.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I earned a Bachelor of Science degree in Mechanical Engineering from Arizona State University and worked as an engineer and power plant supervisor prior to joining APS in 2001. During my years at APS, I have held various frontline and leadership positions including Production Manager at the Company's Cholla Power Plant, Director of Gas and Oil Generation, Director of Coal Generation, Director of Distribution Operations and Maintenance, General Manager of Transmission and Distribution Operations, and Vice President of Transmission and Distribution Operations. I was named to my current position, Senior Vice President of Non-Nuclear Operations, in January of 2020.

Q. WHAT ARE YOUR RESPONSIBILITIES AT APS?

A. I oversee more than 2,500 of APS's union and non-union employees who responsibly ensure the safe, reliable and efficient operations of:

- The Company's non-nuclear generation fleet;
- Environmental, facilities, and transportation services; and
- APS's energy delivery function, which includes system operations, maintenance, engineering, and construction of the transmission and distribution system.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS MATTER?

A. No.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION (ACC OR COMMISSION)?

A. Yes. I provided testimony in the Company's previous rate case in 2016. I have also participated in numerous workshops, open meetings, and other proceedings at the Commission.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to respond to parties' pre-filed direct testimony on post-Test Year plant (PTYP), including APS's Take Charge AZ pilot program, system reliability, and customer solar systems. I also respond to proposals for increased reporting requirements and recommend an alternative set of prudent and useful reports that balance the interests of stakeholders.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. I discuss why the Take Charge AZ pilot project, which is included in the Company's PTYP request, represents a prudent investment. The project was developed consistent with the Electric Vehicle (EV) Policy Statement in Decision No. 77044 (January, 16, 2019) which was in place at the time of its inception, has been positively received by customers, and provides benefits to customers, the environment, and the electric grid.

Aside from the specific example of EV infrastructure, PTYP in general is an important tool to reduce regulatory lag. PTYP should not be arbitrarily reduced by eliminating projects under $5 million. Projects of this size provide value to customers and contribute to important systemwide requirements such as safety and reliability. Cumulatively, they represent significant investments by APS that would otherwise go unrecognized in this proceeding.

APS's current target-setting process based on benchmarking for System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) is a common practice for reducing bias and accommodating uncontrollable variable factors. APS consistently performs at or better than annual Edison Electric Institute (EEI) top quartile reliability, including achieving top quartile SAIFI performance 11 out of the last 12 years and top quartile SAIDI performance nine of the last 12 years. Setting additional external targets can have unintended negative consequences, including increased costs for customers and increased safety risks by diminishing APS's ability to dynamically manage and balance operational risk and system reliability. An example, and as discussed in more detail later, is APS's implementation of proactive wildfire mitigation efforts, which present a reliability trade-off in order to proactively preserve public safety when regional fire conditions are extreme.

APS currently deploys several proactive measures, such as load analysis, inspection programs, and annual summer readiness activities to manage heat impacts and the need for transformer replacements. It is not appropriate or necessary for performance to expend additional funds and labor conducting a separate excessive heat impact study related to outages and equipment replacements. However, the Company continuously evolves its data analytics to review trends in failure causes for its equipment to make the most impactful investments on behalf of customers.

I will cover additional topics, including:

- APS supports providing reliability information to Staff on an annual basis and is available to meet with Staff to discuss the information.

- The revenue requested in this case is necessary for multiple reasons; one of which is APS's need to continue to attract, train, and retain highly skilled workers to continue to provide customers with safe and reliable power.

- SEIA's recommendations to allow residential customer system sizes to be based on inverter settings and to increase the allowed sizes of commercial systems cause concern. If implemented, these changes could negatively impact reliability and increase costs for non-solar customers.

- APS proposes to extend AZ Sun solar asset life by ten years.

III. <u>POST TEST-YEAR PLANT</u>

A. *EV Infrastructure*

Q. DID YOU REVIEW THE PTYP RECOMMENDATIONS FROM THE INTERVENORS' TESTIMONY?

A. Yes. Specifically, I reviewed the testimonies of ChargePoint, EVgo, the Local Unions 387 and 769 of the International Brotherhood of Electrical Workers, AFL-CIO (IBEW), Commission Staff, the Residential Utility Consumer Office (RUCO), and Arizonans for Electric Choice and Competition (AECC).

Q. CHARGEPOINT, EVGO AND IBEW SUPPORT RATE BASE INCLUSION OF THE TAKE CHARGE AZ PROGRAM. DO YOU AGREE WITH THEIR RECOMMENDATIONS REGARDING THAT PROGRAM?

A. Yes. APS agrees that Take Charge AZ should be included in PTYP. The Take Charge AZ pilot program was consistent with the EV Policy Statement in place when the pilot was developed, and thus the costs should be deemed prudent and included in rate base.

APS also agrees that the Commission's EV Policy Implementation Plan (*see* Decision No. 77289 (July 19, 2019)) should be used as a guide for future EV programs.

Q. ARE THERE RECOMMENDATIONS FROM THESE ENTITIES THAT APS OPPOSES?

A. Yes. Specifically, APS does not believe pre-approval from the Commission should be required before implementing future EV charging programs in order to seek cost recovery. While APS is committed to working with the Commission and stakeholders on EV infrastructure investment, an overly prescriptive process can stifle investment and advancement of this technology.

Q. ARE THERE OTHER ASPECTS OF TESTIMONY ON EVS YOU WOULD LIKE TO DISCUSS?

A. Yes. APS would like to acknowledge and support the additional benefits of EV adoption in Arizona that were mentioned in Southwest Energy Efficiency Project and Western Resource Advocates' testimony. Programs such as Take Charge AZ promote the adoption of EVs. EVs provide value for customers, the electric grid, and Arizonans as a whole. EVs are an emerging technology that increase grid utilization, providing flexible demand that can be managed to increase the efficiency of grid assets. EVs help spread the costs of grid infrastructure to customers more evenly and place downward pressure on rates for all customers as load increases due to EVs.

Q. WHAT HAS THE CUSTOMER RESPONSE BEEN TO THE TAKE CHARGE AZ PROGRAM?

A. Since APS launched the Take Charge AZ program in May 2019, customer response has been overwhelmingly positive. The program's pipeline is full (with a waiting list) even without broadly marketing the program.

Q. ARE EVS DISCUSSED BY ANY OTHER APS WITNESS?

A. Yes. APS witness Jessica E. Hobbick discusses EV rate design.

B. *Staff*

Q. DOES APS AGREE WITH STAFF'S PTYP APPROACH?

A. Yes. APS agrees with Staff that PTYP is an important tool that reduces regulatory lag and, when combined with the matching principle of rolling forward accumulated depreciation on existing plant, is an appropriate request. Staff includes APS's requested 12 months of PTYP and updates the projected 12-month period included in the application with actuals provided by APS in discovery.

Q. WITH COVID-19 COMPLICATIONS, HOW WAS STAFF ABLE TO VERIFY THAT THESE PROJECTS WERE ACTUALLY IN SERVICE?

A. At Staff's request, APS provided descriptions and photographic evidence of certain randomly chosen projects that were placed into service during the PTYP period. Please see Attachment JT-01RB for an example of what was provided. Staff's Engineering Report also deems the investments used and useful by this measure.

C. *RUCO*

Q. DOES APS AGREE WITH THE PTYP RECOMMENDATIONS RUCO MADE?

A. No. While RUCO includes 12 months of PTYP, RUCO arbitrarily and inappropriately eliminated APS projects under $5 million for months 6-12 of the PTYP period.

Q. WHAT IS RUCO'S RATIONALE FOR THIS RECOMMENDATION?

A. RUCO cites Docket No. AU-00000A-19-0080, a general docket opened to discuss PTYP policy, and comments made therein as justification for RUCO's recommendation.

Q. WHY DOES APS TAKE ISSUE WITH THIS REASONING?

A. The above docket has not resulted in any ACC conclusions or policy statements regarding what should and should not be included in PTYP. Instead, in the present case, RUCO lists in its testimony a summary of its own opinions filed in Docket No. AU-00000A-19-0080. RUCO witness Frank Radigan writes, "[i]t is my understanding that all stakeholders in the generic proceeding seem to agree that at a minimum the PTYP must be in service by the end of the Post test year, the plant must be used and useful and the plant must be revenue neutral." RUCO Direct Testimony of Frank W. Radigan at 7-8 (Oct. 2, 2020). These are all policies APS has already adopted as part of its application, including for projects under $5 million during months 6-12 of the PTYP.

Q. BUT WHY AN ARBITRARY CUTOFF AT $5 MILLION?

A. RUCO wrongly contends that projects smaller than $5 million will not affect the financial health of a company the size of APS, asserting that investments that only require "middle management" approval should be excluded in PTYP. However, RUCO's recommended reduction is more than 20 percent of APS's entire PTYP request (a reduction of $165 million of rate base). Radigan at 5. More importantly, projects under $5 million are still important and necessary to the efficient and safe operations of the utility and, when prudently invested, should be included in rate base.

To name a few examples, the following projects, each of which cost less than $5 million, were included in PTYP and were critical to the safety, reliability and affordability of APS operations:

- Wood Pole Replacements – The Company's Wood Pole Replacement Program replaces poles with less than ten years of remaining life to reduce distribution outages and mitigate public hazards due to downed poles. These efforts help minimize variable impacts to customers, like outages that may occur during monsoon storms with gusty winds that can blow equipment down. This proactive effort demonstrates a low cost to customers with a significant positive impact on safety and reliability.

- Buckeye 12 kV Substation – This upgrade project, while low in cost, improved the voltage and reactive power support from the Buckeye to Gila Bend substations, an area known for rapid growth and high solar penetration that can impact the voltage levels on the system at key times of the day. This project incorporates power quality and reliability technologies onto the distribution system that respond to voltage variations, limiting impacts and disruptions to customers. In addition, with the proper implementation of this technology, we can reduce electric energy losses and potentially increase the efficiency of the electric distribution system.

- The Yucca controls upgrade on combustion turbines (CT) 1, 2, and 4 are examples of how the Company extends the useful lives of its existing assets through small-investment efforts that increase reliability and maintain affordability for customers. In this case, these units were built in 1971 (CT1 and 2) and 1974 (CT4), and the control systems were obsolete. Replacing these controls reduced repeated outages occurring at the plant and extended operations of the asset without the cost of building a new unit.

- The Sundance CT7 hot section overhaul is an example of the importance of APS's routine reliability maintenance programs, which are critical to the utility's operations and can help control unexpected costs over time. This overhaul represents a prescribed outage in the part of the turbine that sees the most heat and highest pressures from the combustion process. Conducting routine maintenance per industry best practices and the original equipment manufacturer's recommendations helps mitigate safety risks and ensures generating assets routinely run when needed at minimal cost.

Excluding these kinds of projects because they cost less than $5 million would be inconsistent with past PTYP practices and could be detrimental to prudent investment decisions in the future that help control costs and proactively maintain systems on behalf of customers.

IV. APS OPERATIONS AND RELIABILITY

Q. DID YOU REVIEW STAFF WITNESS GURUDATTA BELAVADI'S ENGINEERING ANALYSIS TESTIMONY REGARDING APS'S SYSTEM RELIABILITY AND OUTAGES?

A. Yes.

Q. DO YOU AGREE WITH THE RECOMMENDATIONS PROPOSED BY MR. BELAVADI?

A. APS appreciates Staff witness Belavadi's thorough analysis and support of the operations and overall performance of APS's electric system. The Company generally supports many of the conclusions in Mr. Belavadi's testimony, including that APS's outage programs are reasonable and appropriate, the system is well-planned for and maintained, and the procurement and replacement processes for meters and fleet vehicles are satisfactory.

However, APS does not support the Staff's recommended reliability targets for SAIFI and SAIDI.

While APS agrees it is important to analyze data relative to age and heat impacts on equipment, the Company has not found a strong correlation between this data and the replacement of transformers to warrant the implementation of Staff's recommended targeted excessive heat impact and transformer failure tracking program.

Additionally, APS recognizes the need for information sharing with Staff to provide meaningful insight into the Company's performance. However, APS does not support all of the detailed recommendations for annual reporting requirements included in Staff's testimony. Instead, I suggest later in my testimony an alternative format for annual data sharing, which addresses many of Mr. Belavadi's requests but in a less burdensome and perhaps more useful fashion.

Q. PLEASE FURTHER EXPLAIN YOUR POSITION ON STAFF'S RECOMMENDED RELIABILITY TARGETS FOR SAIFI AND SAIDI.

A. APS's current target-setting process, which aims for annual top quartile reliability as described more below, is widely accepted as a best practice for reducing bias and accommodating uncontrollable variable factors. Setting additional and more stringent externally developed targets, while well intentioned, can have unintended negative consequences. For that reason, APS does not support Staff's recommendation.

APS maintains facilities in a widely diverse service territory composed of both metro load pockets and remote, rural locations. These locations vary greatly with respect to geographical and environmental conditions (i.e., desert and forested), the temperatures to which they are exposed (i.e., extreme cold and extreme heat), as well as the types of storm-related weather conditions they encounter (i.e., snow and ice vs. monsoons and microbursts). Despite this diversity and having the eighth-largest geographic footprint of any U.S. utility, APS has consistently established and achieved annual targets that are comparable to or better than industry-benchmarked top quartile reliability performance metrics.

Given APS's expansive and diverse service territory, external setting of reliability targets could diminish the Company's ability to dynamically manage operational risk and system reliability based on the unique circumstances that may change or develop throughout a given year or over years.

Q. HOW DOES APS APPLY BEST PRACTICES TO DEVELOP RELIABILITY TARGETS?

A. Benchmarking is widely regarded in the industry as an acceptable method to set business goals since it supports non-arbitrary targets without bias.[1] Under this assumption, APS participates annually in EEI's peer benchmarking, which ranks utility performance relative to key metrics. By leveraging the industry's widely recognized EEI benchmarking data, APS establishes annual company goals for SAIDI and SAIFI targeting top quartile reliability. APS consistently performs at or better than annual EEI top quartile reliability, including achieving top quartile SAIFI performance 11 out of the last 12 years and top quartile SAIDI performance nine of the last 12 years. (Refer to Figures 1 and 2.)

[1] Dekker, H. C., Groot, T., & Schoute, M. (2012). Determining performance targets. Behavioral Research in Accounting, 24(2), 21-46.

Figure 1.

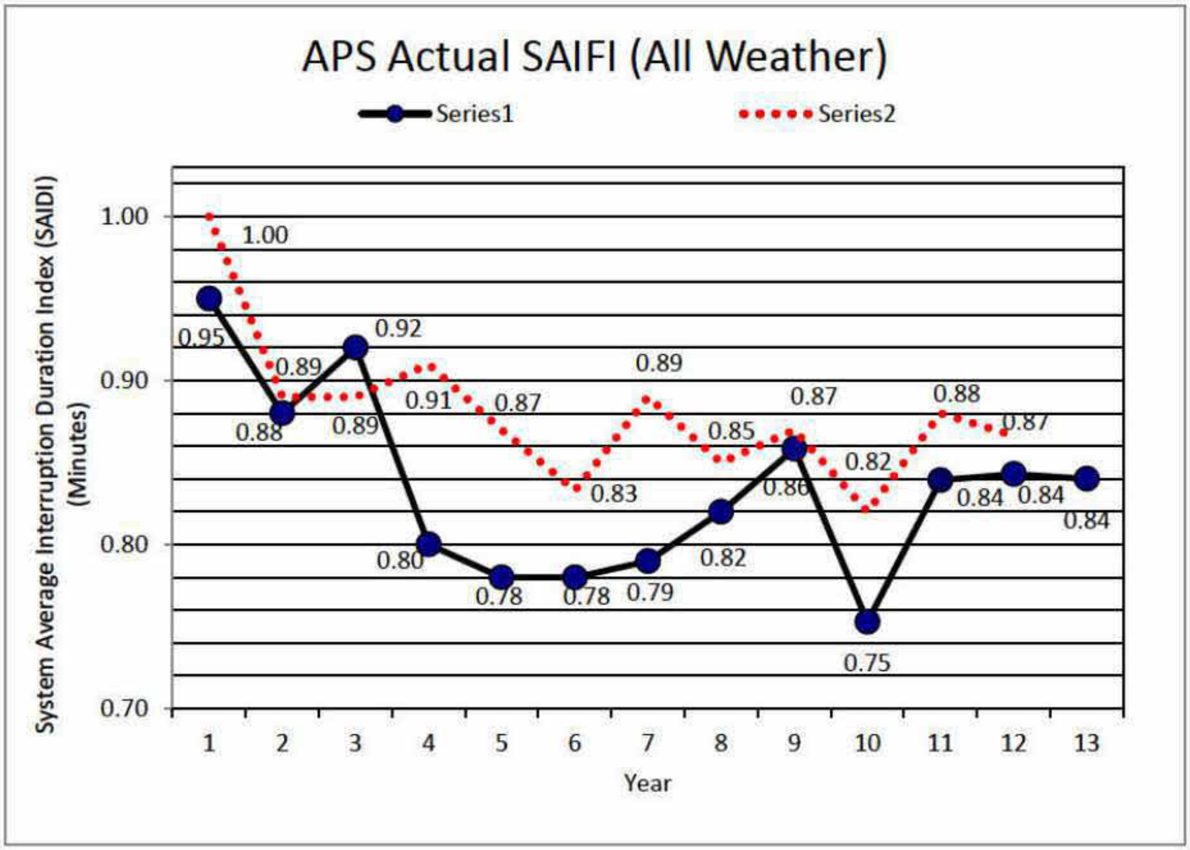
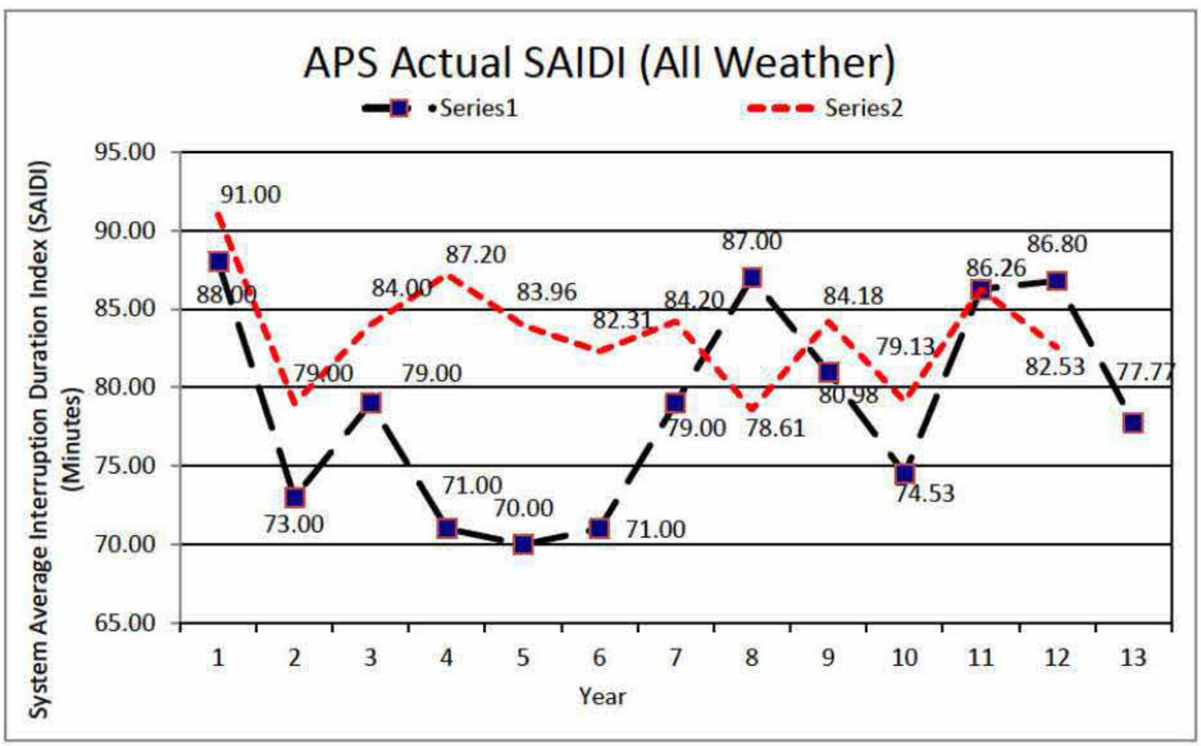


Figure 2.



Q. WHAT ADDITIONAL CONSIDERATIONS DOES APS INCLUDE WHEN SETTING TARGETS?

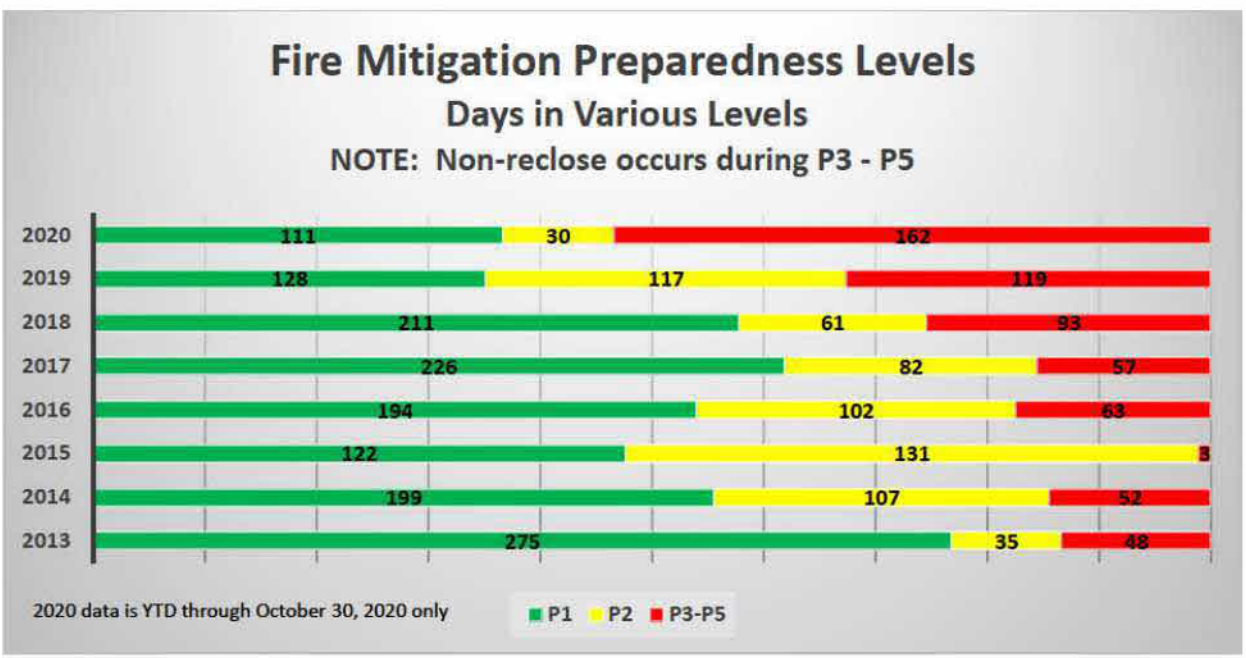
A. Fire mitigation is a prime example in which a utility must make trade-offs between system reliability and overall operational risk. In order to balance these competing demands, the Company must have the flexibility to make the most holistic investment choices necessary to mitigate risks to customers, their communities, and the environment, while providing safe and reliable service to the same stakeholders.

APS continuously enhances its proactive Comprehensive Fire Mitigation Program (CFMP) to further reduce wildfire risk in areas with high wildfire potential. As part of the CFMP, heightened mitigation remedies are put in place when the fire risk measure reaches a certain action level as dictated by local conditions known as Preparedness Levels. Preparedness Levels are dictated by fuel and weather conditions, current and expected fire activity, potential impact to APS's systems and stakeholders, and they are established in close coordination with state and federal agencies. The Preparedness Levels range from one to five, with five being the highest level.

APS's fire mitigation remedies include disabling automatic reclosing on distribution circuits during heightened fire conditions. Under normal operations, these circuit reclosers would automatically detect and restore intermittent faults, much like a home circuit breaker. However, during times of high fire risk a troubleman is deployed to visually patrol lines for potential issues prior to re-energizing to ensure the integrity of the power line. These precautionary measures are employed when conditions in APS's service territory reach a Preparedness Level of three or greater on a scale of five as needed to help protect at-risk communities, but they do negatively impact reliability performance and lead to longer restoration times during outages on nearly 150 identified high-risk distribution and sub-transmission feeders.

Each fire season is unique and varies by many different factors such as rain, heat, and humidity, as well as available resources to combat fire. The state has experienced a steady increase in fire activity in recent years, (refer to Attachment JT-02RB), and regional conditions have increased the number of days in elevated conditions with Preparedness Levels at three or greater (shown as P3-P5 in Figure 3). As of October 30, 2020, APS was still actively in elevated fire conditions and had already experienced 162 days, and counting, in elevated fire conditions year-to-date, up from just 57 days total in 2017 (shown in Figure 3 below). Extended fire seasons such as this year have a clearly defined negative impact on overall system reliability. These variables make it difficult to predict the impact of the fire season on system reliability and precise performance.

Figure 3.



APS's performance reported to EEI includes the unpredictable impacts of proactive fire mitigation. When the impacts for fire mitigation are removed, APS performance in the past four years is well in the top quartile, and 2020 forecasted performance at 0.77 for SAIFI and 71.6 minutes for SAIDI through September 2020 (refer to Figures 4 and 5) is well below Staff's recommended targets of 0.80 and 75 minutes, respectively.

Figure 4.

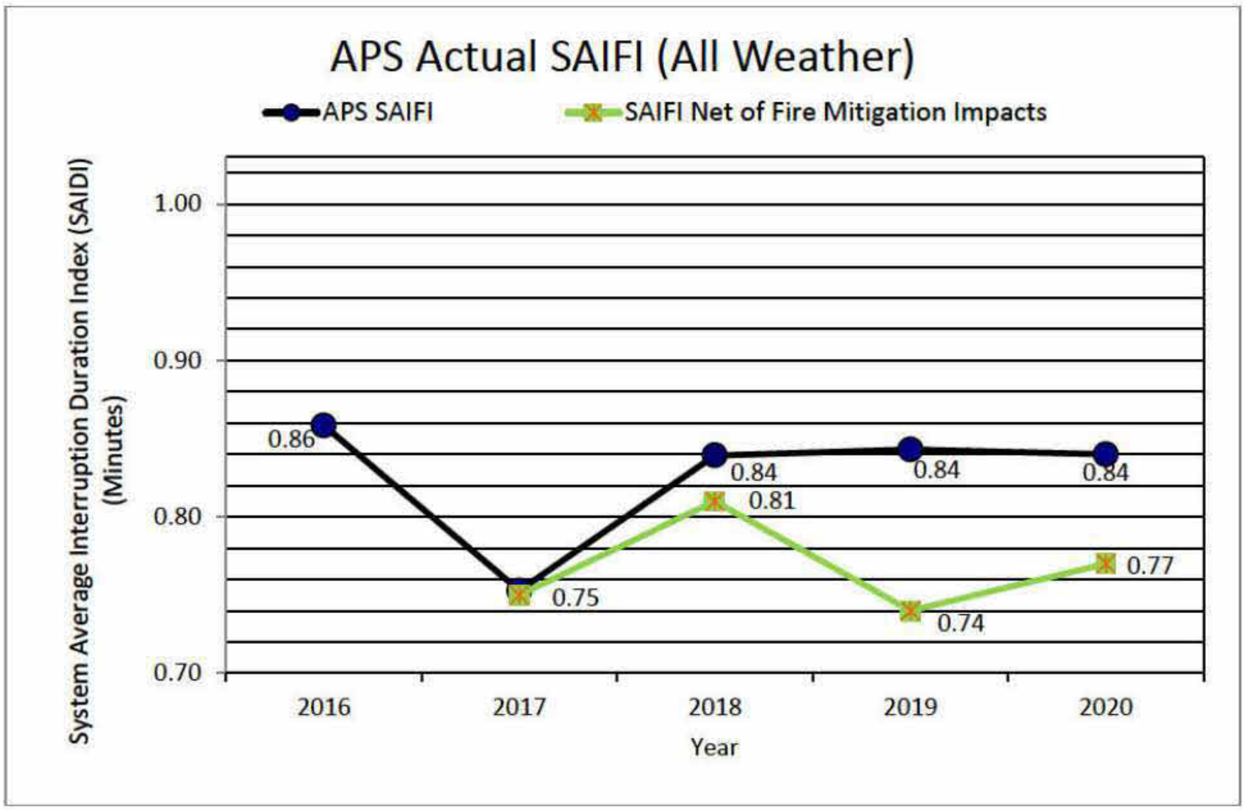
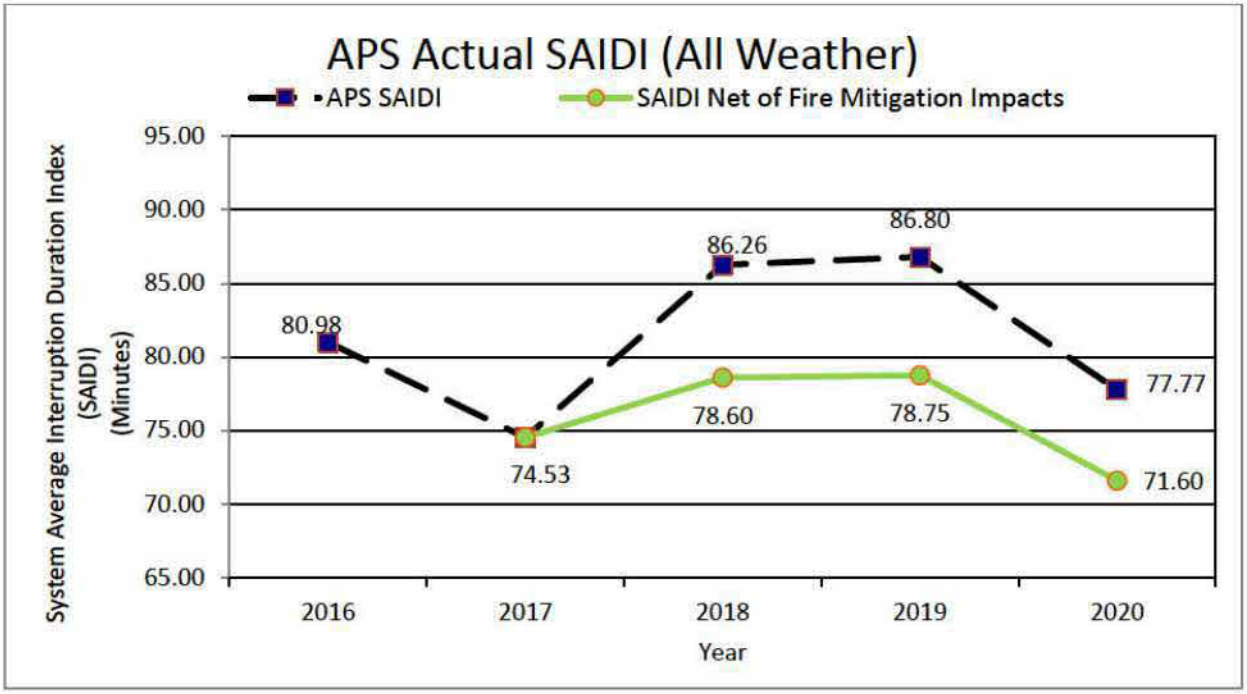


Figure 5.

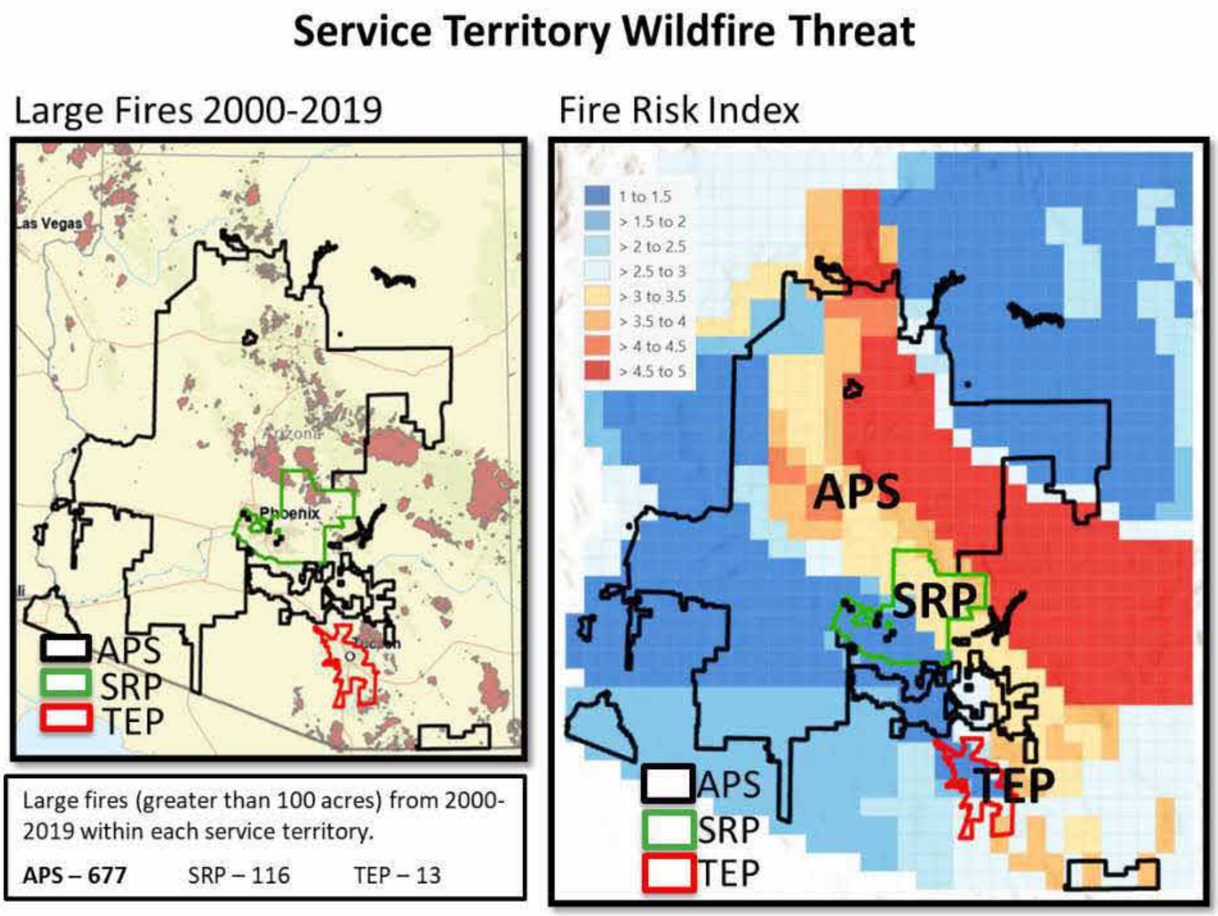


Q. HOW DOES APS'S PERFORMANCE COMPARE TO REGIONAL PEERS?

A. APS performs quite well when compared to a broad and representative group of peer utilities. Unfortunately, APS's public performance data is often compared out of context to the performances of Salt River Project (SRP) and Tucson Electric Power (TEP). However, when compared to SRP and TEP, APS has a significantly larger service territory spanning a much more diverse geography; APS maintains a greater amount of equipment on its system; and APS covers territory that is exposed to greater wildfire risk. As a result of these unique disparities, SRP and TEP do not present a reasonable comparison to APS.

APS's service territory, which spans nearly 35,000 square miles, covers diverse and sometimes forested and mountainous terrain across the state of Arizona. As shown in Figure 6, when compared to SRP and TEP, APS provides service to areas that have experienced more fires since 2000 and represent a greater overall risk of wildfire. As noted earlier in my testimony, fire risk is a variable factor in APS's reliability that often comes with an operational trade-off, sacrificing reliability at times to preserve public safety. Because of the diversity in APS's service territory, it must balance this trade-off to a greater degree than SRP and TEP.

Figure 6.



Furthermore, when simply comparing the size of service territory, APS's service territory is roughly 12 times the size of SRP and 30 times the size of TEP. And, while APS and SRP serve comparable customer population sizes, TEP represents a much smaller overall population size. Plus, APS services a broader population of metro load pockets and expansive, very rural areas of the state, when compared to both SRP and TEP. In addition, APS maintains a far greater number of line miles with roughly 6,000 miles of transmission line and 33,000 miles of distribution line, compared to SRP's roughly 3,000 miles of transmission line and 20,000 miles of distribution line, and TEP's approximate 2,000 miles of transmission line and less than 8,000 miles of distribution line. These differences equate to disproportionately more and often isolated and unprotected equipment on APS's system compared to SRP and TEP.

Therefore, it is more reasonable to compare APS to a broader regional peer set, which yields perspective relative to challenges faced due to service territory size, quantity of equipment operated, geography and wildfire risk. To illustrate this point, APS evaluated its performance relative to the following utilities, as reported to the Energy Information Administration (EIA):

- Tucson Electric Power (TEP)
- Salt River Project (SRP)
- NV Energy (NVE)
    - Nevada Power Company (NPC)
    - Sierra Pacific Power (SPP)
- Public Service Company of Colorado (PSCo)
- Southern California Edison (SCE)
- Portland General Electric (PGE)
- Puget Sound Energy (PSE)

This peer set represents a broad base across the Western Interconnection with considerations for significant load, lengthy transmission lines and geographic exposure to wildfire risk.

Upon reviewing these peers, NVE, which includes both NPC and SPP, represents the most comparable utility to APS in terms of service territory size and customer count, serving roughly 1.2 million customers in a 45,000 square-mile service territory. NVE also services territories most similar to APS's terrain, climate and geography, including comparable miles of total transmission lines in areas with high wildfire potential.

When comparing performance to this peer set holistically, as shown in Figures 7 and 8, APS consistently performs competitively in the middle of the peer set. While SRP and TEP perform lower, or better, than this peer set as a whole, these two utilities also represent a smaller, more dense metro footprint than these comparable utilities. And, when comparing only the performance of APS's metro regions, APS's performance is equal to or better than SRP and TEP, respectively, as shown in Figure 7. This metro comparison removes many of the unique features of APS, including challenges relative to geography, fire risk, and expansive transmission miles that do not exist to the same degree for SRP and TEP. Therefore, a metro-only comparison is a more equitable comparison of these three utilities.

Ultimately, APS maintains competitive performance with its regional peers when compared appropriately for regional and territory constraints.

Figure 7.

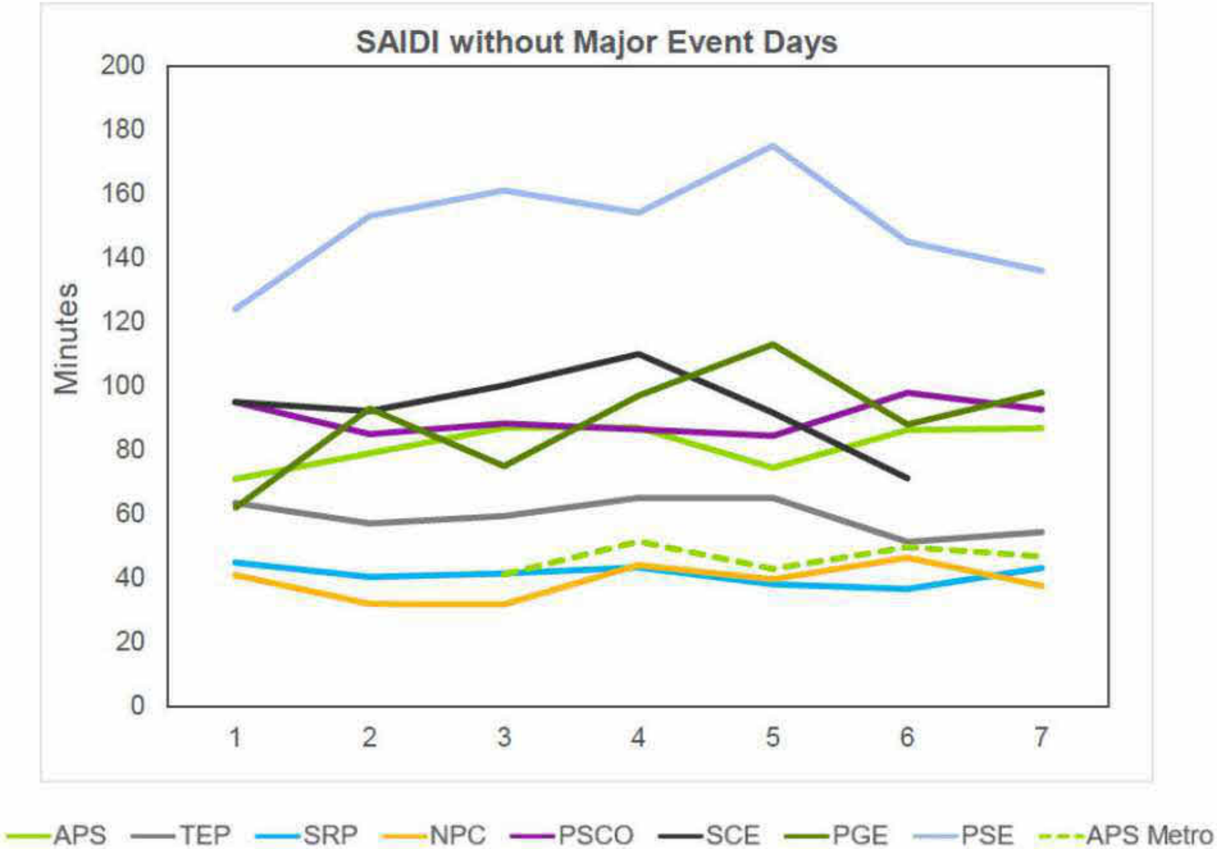
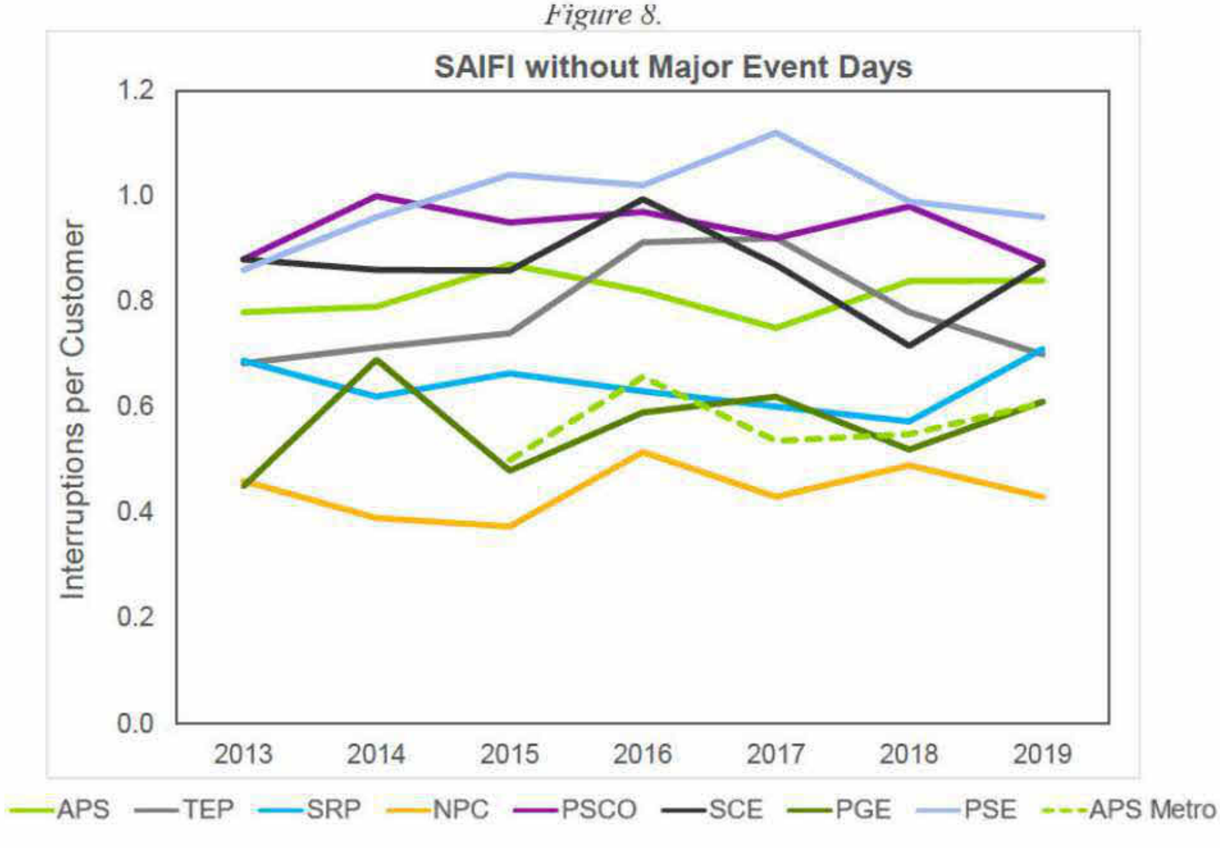


Figure 8.



Q. HOW COULD STAFF'S PROPOSED PRESCRIBED METRIC TARGETS IMPACT CUSTOMERS?

A. APS holds itself to a high standard by setting reliability targets in the top quartile when compared to its peers, and the Company has a proven track record of achieving those goals. In the process of setting these goals, APS is careful to make decisions and set targets that encourage a desirable product both in terms of reliability and affordability. By setting externally prescribed targets, the Company loses the operational flexibility necessary to optimize that balance, while establishing and managing prudent budgets accordingly. Externally set targets may drive unintended system or customer affordability consequences by placing unnecessary pressure on system performance without validation of other variable factors and cost control mechanisms. For that reason, APS does not recommend setting new targets that do not account for environmental variability or the careful balance of investment to maintain customer affordability paired with reliability.

Q. PLEASE FURTHER EXPLAIN YOUR POSITION ON STAFF'S RECOMMENDATION FOR A TARGETED EXCESSIVE HEAT IMPACT AND TRANSFORMER FAILURE TRACKING PROGRAM.

A. APS agrees that analyzing data, including the age at the time of equipment replacement, is important and can provide insights to inform maintenance programs and system enhancements. In fact, APS currently tracks this information and continuously works to improve data analytics capability through current Company initiatives. However, to date, the Company has not discovered any strong correlations between transformer age and impacts of heat to warrant a more targeted approach to addressing these impacts.

As referenced in Staff testimony, APS maintains a system that is adequately and properly maintained and performs with reliability consistent with peer utilities. Staff Direct Testimony of Gurudatta Belavadi at 77 (Oct. 2, 2020). APS actively deploys a number of programs and proactive practices to track asset health and maintain top quartile reliability through engineering analysis and maintenance programs. Transformers, for instance, are routinely inspected and proactively replaced if degradation is observed. These efforts help maintain an annual secondary distribution transformer replacement rate of 1.5 percent or less of the more than 316,000 secondary distribution transformers on APS's grid (refer to Figure 9). This performance is consistent with regional peers.

Figure 9.

	2014	2015	2016	2017	2018	2019	2020 *
Total Replaced	4,059	4,049	3,985	4,269	4,545	4,786	3,045
Average Replacements Per Month	338	337	332	356	379	399	338
Average Replacements (Summer) Month	365	349	457	446	480	429	380
Average Replacements (Non-summer) Months	325	332	270	311	328	384	305
% Delta - Summer to Non-Summer Months	11.0%	5.0%	41.0%	30.3%	31.5%	10.6%	19.5%
Annual Replacements as a % of Total	1.3%	1.3%	1.3%	1.3%	1.4%	1.5%	1.0%

The replacement rate indicated above includes secondary distribution transformer replacements due to vehicle impacts, overloads, leaking, rust and other conditions, and does not simply represent failures. Although summer-month replacement numbers are higher than non-summer months, the number of transformers replaced throughout the year and year-to-year is fairly consistent and is not simply a heat-related summer issue. This is particularly evident in the summer of 2020, which is now the hottest summer on record with 53 days above 110 degrees, and yet the summer monthly transformer replacements were the lowest in the past three years. Given these facts, a separate excessive heat impact study related to outages and equipment replacements beyond what the Company currently performs is unnecessary.

Q. WHAT PROACTIVE MEASURES DOES APS CURRENTLY DEPLOY TO MANAGE HEAT IMPACTS AND TRANSFORMER FAILURE?

A. APS regularly inspects its transformers and actively replaces them when deterioration is observed. To date, APS has not observed a strong correlation between asset age and failure. However, to better understand the impact of both heat and aging on these assets, APS is currently implementing an analysis tool to improve the Company's ability to study transformer failures as needed to inform asset maintenance and replacement strategies.

Additionally, APS leverages load analysis during system upgrades and replacements to ensure new equipment meets capacity needs, with reasonable room for load growth, at the time of installation. APS considers how heat impacts transformer loading and is a factor in the standard specifications, but heat is not the only or even the main driver of transformer failures. Heat and peak load analysis is just one of many programs APS leverages to harden its system and reduce the risk of an outage, including analysis of aged overhead conductors, underground cable replacement, wood pole maintenance and replacement, substation upgrades, and inspection programs.

To prudently manage customer affordability, APS seeks to efficiently balance the cost of investment and reliability expectations of customers through the analysis of available asset performance data. Maintenance decisions are guided on the premise of maintaining top quartile reliability performance. While equipment must be durable, overhardening equipment for heat exposure wastes energy through increased system losses and increases equipment costs, so APS carefully makes this trade-off.

Q. WHAT IMPACT WOULD THE PROPOSED HEAT AND TRANSFORMER REPLACEMENT PROGRAMS HAVE ON CUSTOMERS?

A. APS's current programs allow the Company to affordably mitigate system risk and impacts to customer outages while maintaining equipment replacement rates comparable to or better than industry peers. Any investment to improve reliability comes with a cost to the customer. APS constantly considers this trade-off and invests in areas that maximize return to the customer. The Company is continuously evolving its system analytics and is committed to continuously tracking pertinent data and making decisions based on data analytics and trends.

APS's current practices relative to data tracking and transformer replacement are consistent with regional peers. Implementing additional measures to investigate and potentially mitigate failures caused by heat would provide limited additional benefits, risk increasing system losses and lead to unnecessary costs for customers. However, APS continually reviews asset performance and condition and, if such a program becomes viable, will invest appropriately.

Q. PLEASE FURTHER EXPLAIN YOUR POSITION ON STAFF'S RECOMMENDATION FOR ANNUAL REPORTING REQUIREMENTS.

A. APS is committed to sharing information and data with Staff that provides value and insight to the performance of the Company. APS currently provides outage information to Staff on a regular basis, such as the 1,000 Hour Report, Daily Outage Report, and several other formal and informal data reports. APS agrees with several of Staff's recommendations for annual reporting, including a breakdown of overall system reliability, reliability by region, and descriptions of maintenance programs that help improve system reliability.

APS does not support the following Staff recommendations for reporting requirements:

- Summary of projects and facilities, and their costs, placed into service that aim to improve reliability

- Results summary of excessive heat/outage program(s).

Instead, I propose the following alternative set of reports for Staff, as this alternative set of reports may provide more useful information:

- Overall system reliability performance;

- Performance by geographical region;

- System analysis and reliability impact by top outage cause code types;

- Description of planned reliability maintenance programs; and

- Fire mitigation seasonal impacts.

An example of the proposed Annual Reliability Report can be seen in Attachment JT-03RB. In addition to providing this information on an annual basis, APS is available to meet with Staff to discuss trends and share additional insights.

Q. CAN YOU EXPLAIN THE DISCREPANCY IN THE DATA REPORTED TO THE EIA VERSUS DATA THAT WAS PROVIDED TO STAFF?

A. APS determined the data provided to Staff through the discovery process in response to Staff Discovery Set 13 is correct and reflects accurate SAIDI and SAIFI numbers for 2015 through 2019. The Company is investigating the reporting to EIA to determine the cause of the discrepancy in the EIA data.

Q. DOES APS SUPPORT STAFF'S RECOMMENDATION FOR DIVISION-SPECIFIC STRATEGIES TO REDUCE OUTAGES?

A. APS already employs geographic and weather-related strategies for design and construction standards. For example, the Company designs for snow and ice loading in Northern Arizona, and very dusty regional conditions in areas like Yuma are factored into programs focused on insulator washing. However, APS does not support the notion of individualized outage programs tailored to specific divisions or regions. Instead, the Company leverages data to stay cognizant of the health of the system holistically, and where trends specific to a region may develop. The Company uses that information to influence its designs and standards. This approach informs where reliability improvements are needed and what solutions should be used in each situation. APS uses this data to deploy a variety of programs to address system weaknesses, including low-performing feeders, underground cable issues and wood pole replacement programs, to name a few.

Q. IS THERE ANYTHING ELSE IN MR. BELAVADI'S TESTIMONY YOU WOULD LIKE TO ADDRESS?

A. Mr. Belavadi's testimony highlights a dip in regional performance in the Payson and Prescott areas in 2019. Belavadi at 42. The reliability impacts to both the Payson and Prescott areas in 2019 are directly related to the fire mitigation efforts described above that APS implemented for public safety and risk mitigation. Despite these uncontrollable factors, APS is committed to making informed maintenance investment decisions that improve and manage reliability across its service territory based on analysis of system performance across its territory.

V. <u>IBEW RESPONSE</u>

Q. HAVE YOU REVIEWED THE TESTIMONY OF IBEW WITNESS G. DAVID VANDEVER?

A. Yes.

Q. DO YOU HAVE ANY COMMENTS RELATED TO THE FUNDING AND TRAINING OF EMPLOYEES AS DISCUSSED BY IBEW WITNESS VANDEVER?

A. I agree with IBEW witness Vandever's description of the hiring and employment environment in which APS operates. This is an extremely competitive environment to attract, train and retain highly skilled workers to be able to continue to provide safe, reliable power to customers. The Company's increasing investment in transmission and distribution, along with its generally aging workforce, highlights the need to attract, train and retain highly skilled workers going forward. I also agree that the revenue requested in this case, including the known and measurable union wage increase, will help keep APS financially sound, which will allow us to continue to invest in the programs and people who reliably serve customers.

Q. IS THERE ANY PART OF IBEW'S PROPOSAL THAT APS DOES NOT AGREE WITH?

A. While APS does acknowledge the ongoing need to attract and develop skilled labor provided by IBEW, an additional customer charge to specifically fund that effort is not appropriate at this time. APS can accomplish that goal through the already requested revenue amount.

VI. SEIA RESPONSE

Q. HAVE YOU REVIEWED THE TESTIMONY OF SEIA WITNESS KEVIN LUCAS?

A. Yes.

Q. ARE THERE ANY RECOMMENDATIONS FROM SEIA WITNESS LUCAS YOU WOULD LIKE TO ADDRESS?

A. Yes. Both the recommendation to allow residential customer system sizes to be based on inverter size and the recommendation to increase the allowed sizes of commercial systems could impact reliability and increase costs for non-solar customers. Because feeders have a fixed capacity to add solar, this could also mean fewer customers per circuit are able to add systems.

Q. WHAT IMPACTS TO RELIABILITY COULD BE SEEN BY INCREASING THE LIMITS?

A. APS's engineering teams work to maximize the amount of rooftop solar installed on the distribution system, while maintaining power quality for customers. In areas of high rooftop solar penetration, situations can develop in which the grid experiences voltage and power quality fluctuations, with output intermittency and sustained high voltages around these highly concentrated systems. Rooftop solar can also mask load that affects operators' ability to switch and restore circuits during planned and emergency events. As the size of solar systems increase, the likelihood of these situations occurring increases.

Q. HOW DOES APS WORK TO MANAGE THESE POTENTIAL RELIABILITY IMPACTS?

A. There are currently more than 114,000 residential rooftop solar systems in the APS service territory. Each one of these systems is integrated into the electrical system with modeling and studies performed as needed to ensure safe and reliable operations. APS strives to be a leader in distributed energy resource integration and enable customers to use behind-the-meter technology. Over the past several years, APS has studied the impact of photovoltaic (PV) solar systems on the grid by looking at the system during times of peak solar production with low load to understand the impacts to reliability, and by studying feeders to understand location-based hosting capacities.

Q. WHAT ROLE DO ADVANCED INVERTERS HAVE IN MAINTAINING SYSTEM RELIABILITY?

A. Once advanced inverters become standard in most rooftop solar installations, higher levels of PV can be installed on the system with less investment and required system upgrades. Advanced inverters with appropriate setpoints can regulate voltage at the point of interconnection, even during periods of high intermittency such as cloud cover or dust storms. However, using inverter settings as a replacement for nameplate capacity is inappropriate when qualifying for system interconnection rating because inverters can be sized larger or smaller than the solar system with which they are paired. Further, inverters have a typical life of approximately seven years compared with the longer life of a PV system, which are typically leased for 20 years. By using the size of an inverter to size the system, there is loss of transparency into the size of the PV system that can impact distribution system reliability if the true PV system impact is unknown, or costs to other customers if a customer exports more energy than initially approved.

Q. HOW CAN THE CHANGES RECOMMENDED BY SEIA WITNESS LUCAS IMPACT CUSTOMER COSTS?

A. SEIA witness Lucas refers to limits on PV system size to qualify for the Resource Comparison Proxy (RCP) rate for residential customers and EPR-6 for commercial customers. To qualify for these rates, facilities over 10 kW-dc—the facility's nameplate capacity—cannot be larger than 150 percent of the customer's maximum one-hour peak demand measured in AC over the prior 12 months. (For example, if the customer's peak is 8 kW-ac, the maximum system size that could be installed would be 12 kW-dc.) These PV system size limits are consistent with ACC Decision No. 76295, and were developed to encourage better matching of PV system size to consumption. Since EPR-6 compensates customers for exported solar at a higher price than APS's avoided cost, matching PV system size is also very important. Increasing the limits on PV system size would unfairly burden APS's non-solar customers by requiring non-solar customers to pay for excess generation at a higher rate than APS's avoided cost.

Q. CAN COMMERCIAL CUSTOMERS WITH RENEWABLE ENERGY GOALS INSTALL SYSTEMS GREATER THAN 150 PERCENT OF THEIR MAXIMUM PEAK DEMAND?

A. Yes. Commercial customers who want to install larger PV systems may do so provided the systems meet the requirements in the Distributed Generation Interconnection Rules and there are no physical limitations on the system, such as breaker size. If a commercial customer chooses to install a larger system, the customer would not qualify for EPR-6 and would receive credit for their exported energy under the rate EPR-2. On this rate, customers would receive approximately $0.03/kWh for exported energy, which is closer to the Company's avoided cost, which is currently S0.02254/kWh.

VII. <u>AZ SUN ASSET LIFE</u>

Q. ARE THERE ANY CHANGES TO OPERATIONS THAT IMPACT THE RATE CASE YOU WOULD LIKE TO ADDRESS?

A. Yes. APS is a leader in solar energy and has installed several utility-scale solar systems in the recent past. APS is committed to maintaining the AZ Sun resources to maximize asset life and value for customers. As such, APS proposes an asset life extension to its current AZ Sun utility-scale solar systems by ten years to reduce annual carrying costs for customers and better reflect their expected useful service life.

APS installed the AZ Sun projects from 2011 through 2017, each with an initial proposed life of 30 years. Since those units were placed into service, the Company has gained information and experience in maintaining those assets and believes the life of the assets can be appropriately extended to 40 years. Extending the life of these assets to 40 years is within current industry projections for useful life as supported by organizations such as the National Renewable Energy Laboratory.[2] Following industry best practices and the original equipment manufacturer's standards for maintenance, APS can gain operating efficiency and maximize the life and value of these resources on behalf of customers.

Q. WILL THIS BE DISCUSSED BY ANY OTHER APS WITNESS?

A. Yes. APS witness Dr. Ronald E. White will discuss the financial impacts of depreciation associated with the 40-year proposed asset life.

Q. DO YOU HAVE ANY FURTHER COMMENTS ON ANY INTERVENORS' TESTIMONY?

A. Yes. I did not reference every part of Staff and intervenors' testimony. Not addressing statements or recommendations should not be taken as an endorsement.

VIII. <u>CONCLUSION</u>

Q. PLEASE SUMMARIZE YOUR CONCLUSION.

A. In summary, I conclude the following:

- APS's Take Charge AZ EV program is a prudent investment with benefit to customers that should be included in PTYP.
- PTYP in general is a useful tool and the projects included in APS's PTYP, including those under $5 million, are prudent, useful and critical to the safety and reliability of its system.
- As supported by Staff testimony, APS's electric system is properly maintained, and its reliability is competitive with regional peers.

[2] https://www.nrel.gov/analysis/tech-footprint.html.

- APS does not support Staff's recommendation for externally set targets, which do not appropriately account for operational flexibility to manage risk, like fire mitigation.

- APS acknowledges the importance of tracking asset health data, including the age at the time of replacement. The Company is currently tracking this information and will continue to make investment decisions based on data trends and risk mitigation.

- APS has not observed a strong correlation between heat and age impacts on transformer replacements to warrant changes to its current transformer failure tracking program.

- APS is committed to providing useful data to Staff with insights on the reliability of APS's performance to include:

    - Overall system reliability performance;

    - Performance by geographical region;

    - System analysis and reliability impact by top outage cause code types;

    - Description of planned reliability maintenance programs; and

    - Fire mitigation seasonal impacts.

- The revenue requested in this case is necessary for APS to continue to attract, train and retain highly skilled workers to provide customers with safe and reliable power.

- SEIA's recommendations to allow residential customer system sizes to be based on inverter settings and to increase the allowed sizes of commercial systems should not be implemented.

- Extending the asset life of APS's AZ Sun utility-scale solar assets by ten years is consistent with industry asset projections and would create value for customers.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Sample of PTYP "Used and Useful" Verification

In lieu of a site visit due to COVID-19 constraints, the following photos were provided to Commission Staff to demonstrate the Humbug Feeder Rebuild was used and useful.

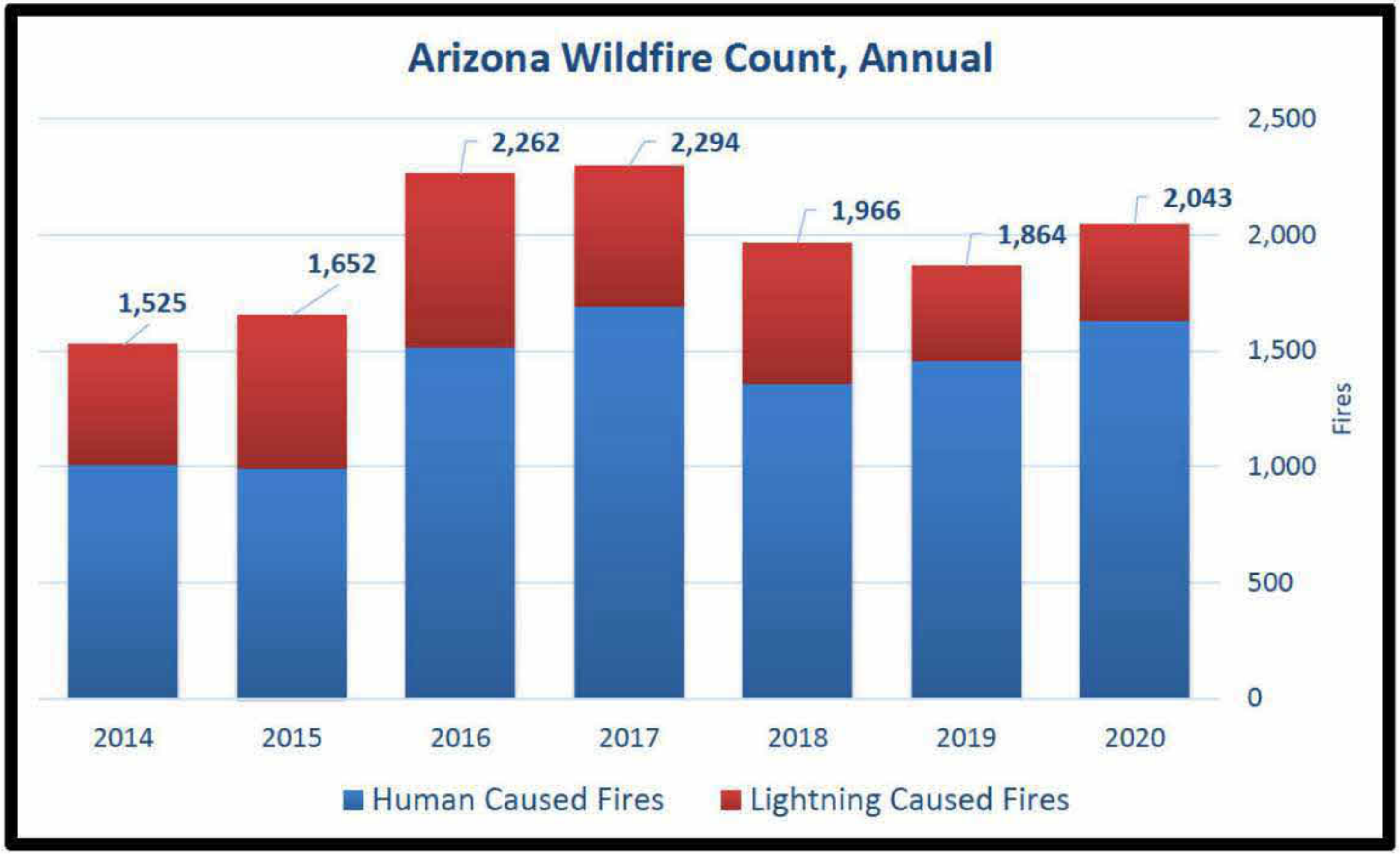

Humbug Rebuild Feeder
APS19RC01681
NO T
REST

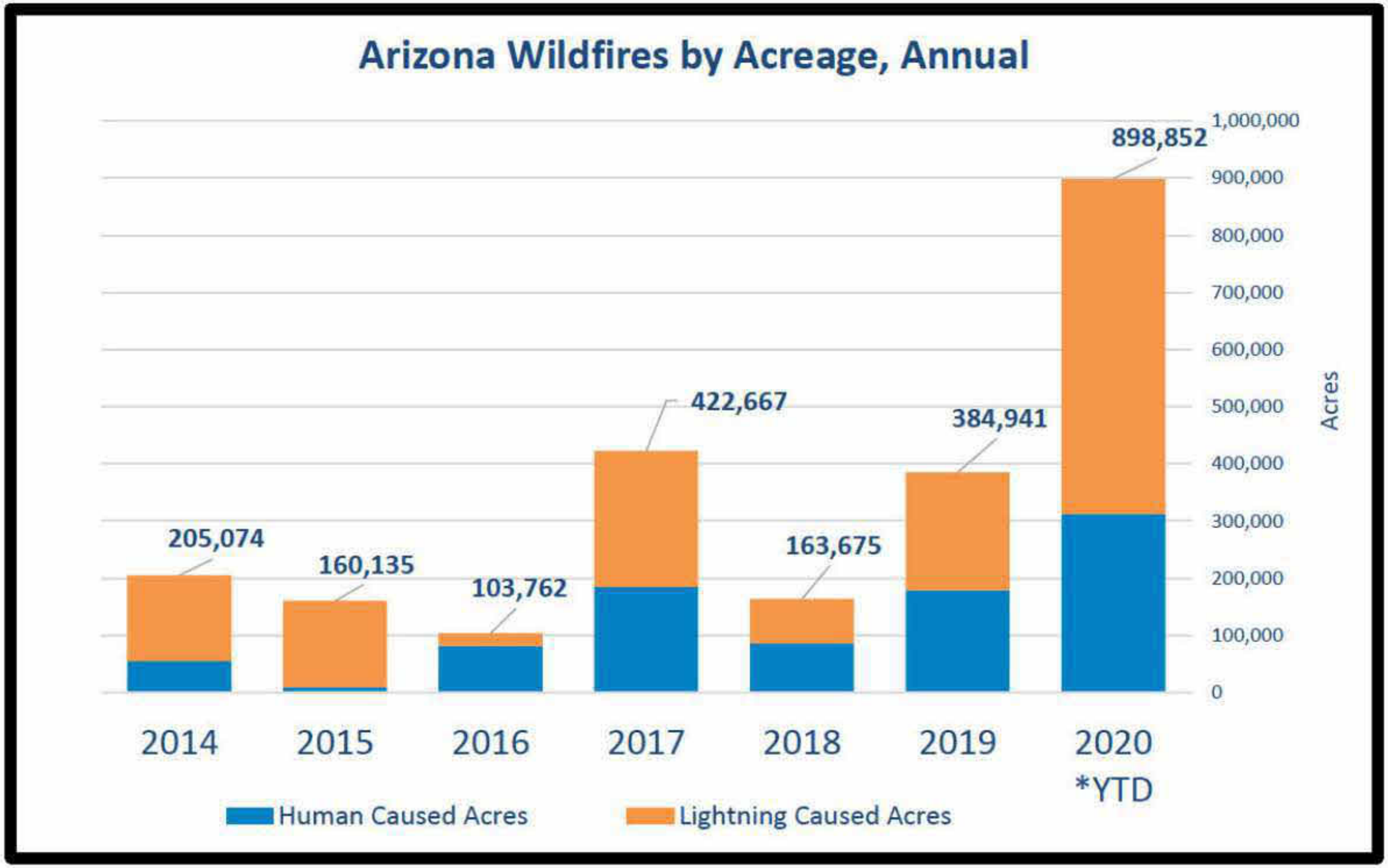

Humbug Rebuild Feeder
APS19RC01682
87TH Ave


Humbug Rebuild Feeder
APS19RC01683


Humbug Rebuild Feeder
APS19RC01684

2020 Summer Fire Season Facts & Figures


Arizona Wildfire Count, Annual
2,500
2,000
1,500
1,000
500
0
Fires
1,525
1,652
2,262
2,294
1,966
1,864
2,043
2014
2015
2016
2017
2018
2019
2020
Human Caused Fires
Lightning Caused Fires


Arizona Wildfires by Acreage, Annual
205,074
160,135
103,762
422,667
163,675
384,941
898,852
1,000,000
900,000
800,000
700,000
600,000
500,000
400,000
300,000
200,000
100,000
0
Acres
2014
2015
2016
2017
2018
2019
2020
*YTD
Human Caused Acres
Lightning Caused Acres

REPORT SAMPLE

Did Arizona Public Service
Sample Annual Reliability Report

Executive Summary

The following report is intended to serve as an illustrative sample only. The data contained within is in example and should not be used as an official record of reliability performance.
APS agrees to work with Commission Staff on formatting that is appropriate and mutually beneficial for both parties. Therefore, formatting and layout is subject to change.

The information provided below is intended to address many of the Commission Staff's requests for annual reporting and visibility to system performance. The items contained within include summaries of the following:

- Overall system reliability performance
- Performance by geographical region
- System analysis and reliability impact by top outage cause code type
- Fire mitigation seasonal impacts
- Description of planned reliability maintenance programs

The illustrative sample begins on page two.

REPORT SAMPLE

2019 Overall System & Regional Reliability Performance

	SAIFI		CW SAIFI	
Division	Actual	Target	Actual	Target
Metro	0.57	0.62	0.5	0.51
State	1.38	1.27	0.83	0.69
NE	1.78	1.45	0.87	0.77
NW	1.69	1.12	0.93	0.55
SE	0.91	1.38	0.64	0.69
SW	1.01	1.17	0.87	0.83
System	**0.843**	**0.84**	**0.611**	**0.57**

SAIFI = System Average Interruption Frequency Index

SAIDI = System Average Interruption Duration Index

MAIFI = Momentary Average Interruption Frequency Index

CW= Clear Weather

AW= All Weather

	SAIDI Minutes		All Weather MAIFI	
Division	Actual	Target	Actual	Target
Metro	49	49	0.43	0.74
State	162	137	1.66	2.12
NE	223	168	2.11	4.48
NW	210	132	1.52	1.5
WgSE	90	139	1.6	1.58
SW	110	106	1.04	1.04
System	**86.8**	**79**	**0.85**	**1.21**

Major Event Days (MEDs):

MED days are not included in the Metric Reporting. The MED threshold for 2019 is 63,415 customer hour interruptions.

5 MEDs: 3/10/2019 (3.2 min), 9/1/2019 (5.75 min), 9/23/2019 (4.15 min), 9/30/2019 (5.1 min), 11/29/2019 (17.2 min)

REPORT SAMPLE

2019 Top Outage Cause Codes

Overall System				
Root Cause	SAIFI Index	% SAIFI	SAIDI Index	% SAIDI
Weather - Storm Related	0.173	20%	0.319	18%
Equipment Failure - APS	0.128	15%	0.269	15%
Unknown	0.085	10%	0.134	8%
Foreign Interference - Vehicles	0.077	9%	0.129	7%
Underground Cable	0.068	8%	0.125	7%
Substation Related	0.063	7%	0.114	6%
Transmission Related	0.061	7%	0.250	14%
Transmission Related (Storm Related)	0.04	5%	0.085	5%
Scheduled - APS	0.039	4%	0.108	6%
Foreign Interference - Birds	0.02	3%	0.021	1%
Foreign Interference - Animals	0.02	2%	0.034	2%
Foreign Interference - Balloons	0.02	2%	0.019	1%
Foreign Interference - Dig-ins Customer/Contractor	0.02	2%	0.018	1%
Weather - Lightning	0.01	1%	0.009	1%
Environment - Fire	0.01	1%	0.036	2%
Overload - Other	0.01	1%	0.018	1%
Foreign Interference - Other Accidental Cause	0.01	1%	0.007	0%
Vegetation Contact	0.01	1%	0.011	1%
Vegetation Contact (Storm Related)	0.00	1%	0.010	1%

REPORT SAMPLE

2019 Fire Risk Mitigation Reliability Impact

TABLE 1. Year End Actuals with and without Fire Mitigation Reliability Impacts.

2019 YEAR END Actuals		
Metric	**Performance with Fire Mitigation Impacts**	**Performance without Fire Mitigation Impacts**
SAIFI	0.843	0.74
CW SAIFI	0.611	0.567
SAIDI (MIN)	86.84	78.75
MAIFI	0.85	1.084

TABLE 2. Fire Mitigation Reliability Impacts By Month.

	June			July		
Metric	5YR	Actual	Delta	5YR	Actual	Delta
AW SAIFI	0.005	0.016	0.011	0.02	0.045	0.025
CW SAIFI	0.004	0.02	0.016	0.003	0.01	0.007
AW SAIDI (min)	0.476	1.543	1.067	1.752	3.184	1.432
MAIFI	0.022	0.004	-0.018	0.105	0.001	-0.104
	August			September		
Metric	5YR	Actual	Delta	5YR	Actual	Delta
AW SAIFI	0.008	0.049	0.041	0.007	0.038	0.031
CW SAIFI	0.002	0.02	0.018	0.004	0.007	0.003
AW SAIDI (min)	0.706	4.436	3.73	0.523	2.381	1.858
MAIFI	0.079	0.019	-0.06	0.035	0.004	-0.031

TABLE 3. Fire Mitigation Reliability Impacts for 2019.

YTD			
Metric	5YA	Actual	Delta
SAIFI	0.039	0.149	0.11
CW SAIFI	0.013	0.057	0.044
SAIDI (MIN)	3.457	11.543	8.09
MAIFI	0.241	0.028	-0.213

REPORT SAMPLE

Overview of Reliability Based Reliability Programs

The lists below represent both maintenance and capital replacement programs that facilitate equipment replacements or preventative maintenance work. These programs are intended to identify equipment-related issues before outages occur and/or support asset upgrades post-event. All of the listed programs improve reliability in some form.

Inspection-Related Programs

Inspection Related Program	Program Description
Transmission Line Maintenance	The Transmission Line Maintenance Program provides maintenance frequency and criteria guidance for the inspections of transmission lines. The purpose of this program is to determine the condition of transmission line equipment and identify issues which may pose safety hazards to the public or compromise system reliability. The results of the inspections also provide documentation in the form of the corrective actions needed.
Wood Pole Maintenance	The purpose of the Wood Pole Maintenance Program is to foster and improve system reliability through the identification and replacement of damaged, defective or failed sub-transmission line wood poles. In addition, the inspection program is the mechanism by which preliminary annual stand-alone project scopes are developed. Those individual projects are then considered for capital budget replacement as a larger project.
Vegetation Management	The Vegetation Management Program provides maintenance frequency and criteria guidance for vegetation management around distribution and transmission circuitry. The program identifies vegetation conditions and growth around Distribution and Transmission conductors that pose a safety hazard to the public or compromise system reliability. Additionally, the program ensures compliance with FERC and ACC regulations and provides documentation of reporting in the form of corrective actions taken in the field. This program also includes herbicide treatments, where applicable.
Thermography Scans	The purpose of the Thermography Scans Program is to detect deterioration and impending failures in certain electrical and mechanical systems through the use of thermal imaging. As an imaging technology, infrared thermography requires no contact with the energized systems and equipment, making it an ideal tool for the power industry to troubleshoot component condition and operational readiness. This program includes scanning elements of the distribution, network, transmission, and substations systems at APS.

REPORT SAMPLE

Circuit Breaker Maintenance	The Circuit Breaker Maintenance Program provides maintenance frequency and criteria guidance for performing minor maintenance (cleaning and lubrication) on circuit breakers. This program includes both distribution class vacuum circuit breakers and sub-transmission and transmission gas circuit breakers.
Transformer & Reactor Oil Sampling	The purpose of the Transformer & Reactor Oil Sampling Program is to monitor and trend dielectric, chemical, and physical condition of the insulation systems within transformers and reactors. This program also provides insights into the remaining operational life of these apparatus. Understanding the health of the insulation systems ensures that the insulation continues to perform its intended function and to avoid a catastrophic failure of these high value components.
Recloser & Sectionalizer Maintenance	The Reclosers & Sectionalizer Maintenance Program maintains the growing fleet of equipment through consistent maintenance, testing, and replacement of APS's reclosing assets. Reclosers play a critical role in grid reliability, especially in more remote locations, due to their automatic sensing and activation capabilities. This program performs organized time-based inspections on each device throughout the system in addition to replacing a select number of antiquated, hydraulic-style non-communicating devices with modern technology annually.
Switching Cabinet Inspections	The purpose of the Switching Cabinet Inspections Program is to inspect and replace pad-mounted distribution cabinets to maintain feeder reliability, deliver power effectively to customers, and maintain public safety. The cabinets are inspected for rust, broken hinges, door misalignment, and pad cracks or breaks.
Automatic Transfer Switch Maintenance	As part of grid modernization, more remotely operated switching capability is being added to the grid. The Automatic Transfer Switch Maintenance Program provides maintenance frequency and criteria for performing maintenance on automatic switching devices. This program also modernizes the grid by identifying switches that need motor operators and communication capabilities.

REPORT SAMPLE

Replacement-Related Programs

Replacement Related Program	Program Description
Substation Transformer Replacement	The purpose of the Substation Transformer Replacement Program is to replace high-risk, end-of-life substation class transformers prior to failure. Candidates for replacement are considered based upon condition health assessments, testing, criticality, and defined replacement criteria.
Substation Aged Equipment	The purpose of the Substation Aged Equipment Program is to replace aging substation equipment prior to an unplanned failure, which often results in outages. Equipment can be at end-of -service life, problematic or in an advanced degraded state due to loading and/or operation. Engineering evaluates the condition of these assets, prioritizes and recommends a list of assets to be replaced on an annual basis.
Aged Conductor	The purpose of the Aged Conductor Program is to improve reliability and reduce safety risks through the replacement of legacy overhead distribution conductor. The program targets feeders with a high density of aged conductor to be replaced with updated standard line. The program intent is to re-conductor all legacy, undersized wires with standard wire to reduce wire down events due to fault conditions or weather events.
High SAIFI Feeder Program	The High SAIFI Feeder Program focuses on improving system reliability through identifying the worst performing feeders. The identified feeders are analyzed by engineering and inspected by a designated reliability crew to coordinate solutions to improve feeder performance. This program provides funding for costly improvement solutions that might be identified such as wire replacement, pole replacements, equipment upgrades, etc.
Network Equipment Replacement Program	The purpose of the Network Equipment Replacement Program is to improve the safety and reliability of our network by preventing catastrophic failure of network equipment. The program targets equipment at the end of life and includes the installation of Supervisory Control and Data Acquisition (SCADA) systems. SCADA allows the monitoring of equipment health serving key account customers such as hospitals, banks, high rise buildings and data centers. Monitoring equipment health enables APS to modify maintenance plans and position for a proactive approach to equipment replacement.

REPORT SAMPLE

Overhead Planned Replacement	The purpose of the Overhead Planned Replacement Program is to foster and improve system reliability through the identification and sequential replacement of damaged, defective or failed line equipment. The program addresses both the APS transmission and distribution electrical grid system voltage classes. In addition, the inspection program is the mechanism by which preliminary annual stand-alone project scopes are developed and prioritized in the annual budgeting process.
Wood Pole Replacement	The purpose of the Wood Pole Replacement Program is to foster and improve system reliability through regular inspections and maintenance, including total replacement of wood poles. Failures of these poles can interrupt service to customers, present a public safety hazard and result in costly emergency repairs. In recognition of these risks, Section 6 of the National Electric Safety Code requires utilities to regularly inspect and maintain the poles in their system.
Underground Cable Replacement	The purpose of the Underground Cable Replacement Program is to improve system reliability by systematically replacing all of the remaining direct buried primary distribution cable in a cost-effective and efficient manner. At times, replacement of cable already installed in conduit may be included in this program in special circumstances.
Underground Transformer Replacement	The purpose of the Underground Transformer Replacement Program is to improve the safety and reliability of APS's underground system by replacing pad-mounted distribution transformers due to end-of-life conditions such as broken hinges, rusting enclosures, leaking oil and broken pads.
Serveron Program	The purpose of the Serveron Program is to remotely monitor dissolved gas analysis (DGA) of the fleet's extra high voltage (EHV) transformers/shunt reactors and automatically report transformer system health anomalies in order to avoid unplanned failures, lower maintenance costs, and improve reliability.

ATTACHMENT 6

REBUTTAL TESTIMONY OF JESSICA E. HOBBICK

On Behalf of Arizona Public Service Company

Docket No. E-01345A-19-0236

November 6, 2020

Table of Contents

REBUTTAL TESTIMONY OF JESSICA E. HOBBICK
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-19-0236)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jessica E. Hobbick. My business address is 400 N. 5th Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS MATTER?

A. Yes. I filed direct testimony submitted with Arizona Public Service Company's (APS or Company) application.

Q. ARE THERE ANY ADDITIONS TO YOUR PROFESSIONAL EXPERIENCE?

A. Yes. My professional experience now includes having graduated Magna Cum Laude from Grand Canyon University with a Bachelor of Science degree in Business Management.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to introduce APS's proposed changes to simplify residential rate plan options in response to intervenor and public comment and to respond to parts of the direct testimony from Staff and intervenors.

II. SUMMARY

Q. PLEASE SUMMARIZE ANY CHANGES TO APS'S MAJOR RATE PROPOSALS.

A. After receiving feedback from a variety of stakeholders and intervening parties in this case, APS appreciates the need to simplify residential rate plan offerings. Given this feedback, APS is now proposing changes that would consolidate its existing six residential rate schedules into three options that would be available to all eligible residential customers, including one flat rate, one time-of-use (TOU) rate, and one demand rate. Flat rates will be available for all non-solar residential customers, regardless of usage. The basic suite of flat rate plans, including 1) R-XS (Lite Choice); 2) R-Basic (Premier Choice); and 3) R-Basic Large (Premier Choice Large), which is currently frozen, will be combined into one streamlined rate schedule with three usage groups that have differentiated energy and basic service charges that customers would be placed within annually based on the average monthly usage consumed during the previous 12 months. This change will make flat rates available for all non-solar residential customers, regardless of their usage.

APS proposes to maintain its existing time of use rate R-TOU-E (Saver Choice). And, to simplify its demand rates, APS proposes to freeze the R-2 (Saver Choice Plus) demand rate plan, making it unavailable for new customers, while allowing existing customers who have already selected R-2 to remain on that rate plan. Consequently, R-3 (Saver Choice Max) would be the only demand rate plan option available to new customers going forward.

These proposed changes will further benefit customers by eliminating the current 90-day TOU trial period for new customers as well as eliminating the reassignment of larger usage customers from the flat rate to a TOU rate when their usage exceeds the current flat rate eligibility requirements.

Q. WHAT ELSE IS COVERED IN THIS TESTIMONY?

A. APS is updating its request for an overall increase in retail revenue to a base rate increase of $41 million or 1.23%, resulting in a net impact of 5.14% when the adjustor impacts are considered.[1] This represents a reduction of $15 million from APS's original application. The updated request is distributed evenly among rate classes in a manner consistent with the initial application. I discuss why revenue distribution proposals from intervenors Walmart Inc. (Walmart) and Federal

[1] Numbers are rounded for ease of discussion.

Executive Agencies (FEA) would generally decrease costs for large business customers to the detriment of residential customers.

I respond to a number of changes in residential rate design proposed by Staff and intervenors that APS does not support, including modifications to the TOU hours, changes to the seasonal months and rates, differences in the ratio of on-peak to off-peak prices, reductions in the basic service charges, and untimed demand charges. In general, these proposals run counter to APS's goals to limit a broad range of bill impacts to residential customers and simplify rate features and options. While I may not address every detail related to intervenors' recommendations, it should not be interpreted that I agree with each position unless specifically stated within my testimony.

Lastly, I discuss revising Service Schedule 1 to lengthen the amount of time APS's customers have to remit payment after a bill is issued from 14 days to 21 days to align its practice more closely with other utilities and to improve customer satisfaction.

III. UPDATED REVENUE REQUIREMENT AND ALLOCATION TO RATE CLASSES

Q. WHAT IS THE COMPANY'S UPDATED REQUEST FOR AN OVERALL INCREASE IN RETAIL REVENUE?

A. The updated request has been reduced based on adjustments described in APS witness Leland Snook's testimony. This brings the original base rate increase down from $69 million to $41 million, which represents an overall base rate increase of 1.23%. Once the tax expense adjustor mechanism and environmental surcharge transfers to base rates are factored in, and the Advanced Energy Mechanism is added, this results in an overall net impact to customers of 5.14%. The net impact to the residential class specifically is 4.99% and the general service net impact is 5.33% when the Advanced Energy Mechanism is spread across classes based on kWh sales.

Q. HOW IS THE UPDATED REVENUE REQUIREMENT ALLOCATED TO THE VARIOUS RATE CLASSES?

A. The updated request is allocated among rate classes in a manner consistent with APS's initial application. APS proposes an even distribution of the average increase across the rate classes to avoid disparate impacts between rate classes. Residential Utility Consumer Office (RUCO) witness Frank Radigan supports APS's recommendation to spread the retail revenue change equally across customer classes.

Q. WHAT JUSTIFICATION SUPPORTS THIS EVEN DISTRIBUTION OF REVENUE?

A. When APS implemented the rates approved in Decision No. 76295 (August 18, 2017), one of the primary areas of focus was to realign rates with costs; thus, the allocation of the revenue increase approved by the Arizona Corporation Commission (Commission) reflected those efforts. As a result of those efforts to create a closer connection between rates and cost causation across the rate classes, the net impact to residential customers in the last rate case was 4.54%, and the net impact to the general service class was 1.87%, as shown in Table 1. Significant progress was made in the last rate case on improving the revenue allocation, thus, it is appropriate here to spread the proposed increase evenly and avoid significant increases to any one particular class. For that reason, APS continues to recommend an average distribution of the proposed increase, which is also supported by RUCO.

Table 1. Revenue from Base Rates under Present and Proposed Rates 2016 Rate Case

Revenue from Base Rates under Present and Proposed Rates

Line No.	Customer Classification	(A) Present Rates [1,2] ($000)	(B) Proposed Rates [2] ($000)	(C) Change ($000) (B) - (A)	(D) % (C) / (A)	(E) Adjustor Transfers [3] ($000)	(F) Net Change ($000) (C) - (E)	(G) Net Increase [4] % (F) / (A)
1.	Residential	1,486,578	1,722,984	236,406	15.90%	168,861	67,545	4.54%
2.	General Service	1,343,926	1,463,595	119,669	8.90%	94,547	25,122	1.87%
3.	Irrigation/Water Pumping	28,739	32,952	4,213	14.66%	3,248	965	3.36%
4.	Outdoor Lighting	21,082	22,708	1,626	7.71%	982	644	3.05%
5.	Dusk to Dawn Lighting Service	8,578	9,240	662	7.72%	313	349	4.07%
6.	Total Sales to Ultimate Retail Customers	2,888,903	3,251,479	362,576	12.55%	267,951	94,625	3.28%

Q. ARE THERE INSTANCES WHERE THE ALLOCATION OF REVENUE CREATES INCONSISTENT IMPACTS FOR RATE CLASSES IN YOUR PROPOSAL?

A. Yes. The net impact, which includes both the increase to base rates and the adjustor transfers, among classes ranged from 5.41% to 5.82%, as shown below in Table 2, as well as SFR H-1 filed with the original application. The numbers in the base rate increase ranged from 1.33% to 3.64% in that same schedule. Arizona School Board Association (ASBA) witness Travis Sarver asserts that the increase to the GS Schools was higher than the amount applied to other classes although the base rate increase applied to this class was 2.69% and the net impact was 5.60%, both of which are within the ranges described. The primary driver behind the difference in this range of impacts is the result of the transfer of the Tax Expense Adjustor Mechanism (TEAM) into base rates. For simplicity, the TEAM adjustor refunded the benefit of the lower income tax rate as a cents per kWh, although income taxes are generally allocated in cost of service using class revenues. This means that some classes received a disproportionate benefit of the tax credit through the adjustor as compared to what they will receive when the federal tax rate is directly reflected in rates. To mitigate these impacts, slight adjustments were made in rate design to achieve a narrow range of net impacts and maintain a near even distribution of revenue across classes, as seen in Table 2.

Table 2. Net Rate Impact by Customer Class

	Base Revenues in the Test Year (a)		Proposed Increase (b)				
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Customer Classification	Present Rates [1,2] ($000)	Proposed Rates [2] ($000)	Change ($000)	%	Adjustor Transfers [3] ($000)	Net Change ($000)	Net Increase [4] %
			(B) - (A)	(C) / (A)		(C) - (E)	(F) / (A)
Residential	1,740,264	1,779,205	38,941	2.24%	(55,268)	94,209	5.41%
General Service	1,476,858	1,504,994	28,136	1.91%	(57,816)	85,952	5.82%
Irrigation/Water Pumping	32,188	32,615	427	1.33%	(1,374)	1,801	5.60%
Outdoor Lighting	20,814	21,572	758	3.64%	(407)	1,165	5.60%
Dusk to Dawn Lighting Service	9,067	9,396	329	3.63%	(177)	506	5.58%
Total Sales to Ultimate Retail Customers	3,279,191	3,347,782	68,591	2.09%	(115,042)	183,633	5.60%

Q. DO YOU AGREE WITH THE REVENUE ALLOCATIONS PROPOSED BY INTERVENORS WALMART AND FEA?

A. No, their proposals would generally decrease costs for large business customers to the detriment of residential customers. Walmart witness Steve Chriss' proposal in his Direct Testimony (Walmart Direct Testimony of Steve W. Chriss at 7, Table 2 (Oct. 9, 2020)) would result in allocating approximately $200 million dollars more to the residential class, roughly five times the amount proposed by APS, while decreasing rates for other non-residential classes. Similarly, under FEA witness Amanda Alderson's proposed revenue spread reflected in attachment AMA-6DR, the residential class would be allocated more than $149 million dollars of the $183.6 million increase requested in APS's application.

Q. DO YOU AGREE WITH THE REVENUE ALLOCATION PROPOSED BY STAFF?

A. No. APS does not agree with Staff witness David Dismukes' proposed allocation which would reduce rates to all customers, with those rate classes reflecting a rate of return that is less than the Company's average receiving half of the overall average decrease. The Company does, however, agree with several points made within Staff witness Dismukes' testimony that encourage the use of gradualism to protect customers from rate shock, the importance of maintaining rate continuity, and his emphasis that the cost of service is not the only factor to use in rate development (Staff Direct Testimony of David E. Dismukes, PHD at 22-23 (Oct. 9, 2020)).

IV. <u>RESIDENTIAL RATE DESIGN</u>

Q. WHY IS APS PROPOSING TO CONSOLIDATE RESIDENTIAL RATES AT THIS TIME?

A. APS supports the desire to streamline its rate offerings to make it easier for customers to distinguish between the rates and choose the rate that is best for them. The changes APS proposes will simplify rates while still providing customer choice: one flat rate, one TOU rate, and one demand rate.

Specifically, APS proposes consolidating its current family of basic, or flat rates, into one rate schedule and making it available to all non-solar customers. This change streamlines the basic rate offerings, which are identical in structure, with customer and energy charges that would continue to differentiate between small-, medium-, and large-use residential customers and better align with the cost to serve them. Customers would continue to select the energy use tier for which they are eligible based on their annual average monthly usage consumed during the previous 12 months and be billed on the corresponding rates.

APS also proposes moving to one residential demand rate. Under the present rate structure, customers may choose between two demand rates, R-2 (Saver Choice Plus) and R-3 (Saver Choice Max). Freezing R-2 going forward obviates any potential confusion about the differences between the two demand rates, while at the same time preserving a demand rate option for customers, a choice that residential customers have had for nearly 40 years. APS recommends keeping R-3 (rather than R-2) going forward because the R-3 rate plan has resulted more frequently in customer bill savings, and 46.7% of existing customers on R-2 today would have saved money annually if they were on R-3.

Q. HOW WILL THESE CHANGES AFFECT THE 90-DAY TRIAL PERIOD FOR NEW CUSTOMERS THAT CURRENTLY EXISTS?

A. Currently, new customers who will likely consume an average of 600 kWh or more per month are required to first select a TOU rate before they have the option to choose a basic rate. Upon the conclusion of that trial period, customers are provided with a notification that additional rate options are available and customers are encouraged to visit aps.com or contact the Customer Care Center and discuss available rate options with an APS Advisor. APS agrees with Staff witness Dismukes' recommendation to eliminate the 90-day trial period and is proposing that it be discontinued so customers who consume 600 kWh or more also have the flexibility to select any one of the three rate schedule options available. Although the TOU-E rate option often results in savings for customers who consume more than 1,000 kWh monthly, monthly pro forma billing will be used to continue to inform customers of the additional choice while preserving their preference to enroll in a basic rate.

Q. ARE THERE ADDITIONAL BENEFITS TO CUSTOMERS IN SIMPLIFYING RESIDENTIAL RATE STRUCTURES?

A. Yes. This simplification modifies the annual rate reassignment process to allow customers to remain on a basic rate structure if they so choose. Currently, customers on R-Basic (Premier Choice) who exceed an average monthly usage level of 1,000 kWh are reassigned to R-TOU-E (Saver Choice). For some customers, the transition from a basic energy-only rate to a TOU rate may not align with their preferences and cause confusion or dissatisfaction. I will note that one reason this approach was taken previously is that generally customers of this size find more benefit, from a strictly economic perspective, being on a TOU rate. Opening up flat rates for customers with usage above 1,000 kWh a month may likely cause more customers to not be on their most economical plan (MEP).

APS supports the suggestion by RUCO witness Radigan that the annual rate reassignment be modified to favor customer choice, and the Company recommends unfreezing R-Basic Large (Premier Choice Large) to allow customers to remain on a basic structure should their average monthly usage increase.

Q. WHAT IS THE REVENUE IMPACT OF THE RESIDENTIAL RATE CHANGES DESCRIBED?

A. There is no revenue impact associated with the changes to consolidate the basic suite of rates and unfreeze R-Basic Large (Premier Choice Large). Similarly, because the proposal is to freeze R-2 (Saver Choice Plus) with the current level of customer enrollment and not migrate those customers to another rate, there is no revenue impact that results from that change either.

Q. AMERICAN ASSOCIATION OF RETIRED PERSONS (AARP) WITNESS SCOTT RUBIN ASSERTS THAT APS FAILED TO ENFORCE THE RATE REASSIGNMENT RULES IN PLACE. DO YOU AGREE WITH HIS ASSESSMENT?

A. No. Under the rules in the tariff, APS reassigned 61,320 customers in 2018 and 59,984 customers in 2019. The reason AARP witness Rubin believes there are 32,420 customers enrolled in rates for which they are not eligible is because he used a period of time to determine average monthly usage that is different than the actual reassignment process. Because the annual rate reassignment occurs at the end of the calendar year, the average monthly usage consumed during the actual period evaluated, December 2018 through November 2019, differed from the average monthly usage calculated by AARP. AARP incorrectly used the split Test Year average information to reach its conclusion, rather than end of year information. Notably, AARP's suggestion would have resulted in undercollection of $1.77 million. APS confirmed this as the cause of the alleged discrepancy by recreating both the calculation of the average monthly usage during the Test Year and the actual period that would have been used for reassignment.

Q. DOES APS PLAN ANY ADDITONAL CHANGES TO THE RATE REASSIGNMENT PROCESS?

A. Yes. To further improve customer satisfaction and understanding of the rate design, APS proposes to allow customers to call the APS Customer Care Center and be moved back down to their initial usage tier the first time they are bumped up to a higher tier via reassignment. Advisors will provide helpful tools to assist customers in monitoring the amount of energy consumed monthly such as usage notifications or information available on the bill and aps.com so they are prepared for future reassignments. APS will add this clarification to its Service Schedule 1 if approved by the Commission.

Q. DOES APS SUPPORT DEFAULT RATES AS PROPOSED BY SOUTHWEST ENERGY EFFICIENCY PROJECT (SWEEP), WESTERN RESOURCE ADVOCATES (WRA) AND AARP?

A. No, APS does not support the proposal put forth by SWEEP, WRA to default all new customers to a TOU rate. Nor does APS support AARP's proposal to default customers to specific types of rates based on usage. While there can be benefits to default rates, APS's proposal supports allowing customers to choose the rate that is right for them while also simplifying the rate offerings. APS disagrees with the premise put forth by some intervenors that a customer who does not select his or her MEP must not understand the available rates. In Guidehouse's *Review of the 2017 Customer Education and Outreach Plan & Response to the Plan*, attached to the Rebuttal Testimony of APS witness Monica Whiting as Attachment MW-03RB, they support that "Given the preference for the status quo, programs that are unaware of this bias may incorrectly interpret people's failure to actively make a choice as an indication of low levels of awareness, irrational behavior or poor program execution." (Guidehouse Report at 43.) Much like a customer who chooses an unlimited data plan through a cell phone provider, there may be some months when a lower-cost plan might have met the customer's data needs, but ultimately the customer selects the plan that works best for that customer given the totality of the circumstances.

Q. DID INTERVENORS PROPOSE CHANGES TO APS'S SUITE OF RESIDENTIAL RATES?

A. Yes. Several changes were recommended by intervening parties, some of which are being adopted by APS while others are not. Changes that APS does not support include modifications to the TOU hours, changes to the seasonal months and rates, differences in the ratio of on-peak to off-peak prices, reductions in the basic service charges, and even untimed demand charges that would require customers to manage their level of consumption 24 hours a day, seven days a week.

Q. WHY DOES APS NOT AGREE WITH THESE PROPOSALS?

A. As I discuss in further detail below, the goals of APS's proposed rate design changes in this case are to limit a broad range of bill impacts to residential customers and to focus on efforts that simplify rate features and options, and therefore intervenor proposals were evaluated through this lens.

Q. DOES APS SUPPORT CHANGING ITS RESIDENTIAL ON-PEAK HOURS?

A. No.

Q. WHY ARE THE CURRENT ON-PEAK HOURS OF 3:00 P.M. TO 8:00 P.M. MONDAY THROUGH FRIDAY APPROPRIATE?

A. APS witness Brad Albert explains the basis for selecting 3:00 p.m. to 8:00 p.m. Monday through Friday as on-peak hours. APS witness Albert provides evidence that this time period correlates with APS's system peak and explains why it is important to send correct price signals to customers that encourage conservation during these hours based on system load and resources.

Q. EXPLAIN WHY CHANGING THE ON-PEAK HOURS IS NOT RECOMMENDED IN THIS CASE.

A. In addition to the fact that these hours reflect the actual APS system peak, there are several additional reasons to leave the current on-peak hours intact, including customer stability, avoiding a broad range of bill impacts driven by different customer usage patterns during different time periods, and the challenges in informing customer rate selection using historical data when on-peak hours, which are used to influence customer energy use, change. In its last rate case, APS reduced the number of on-peak hours, decreasing them from a seven-hour window, which ran from noon to 7:00 p.m., to the current five-hour period of 3:00 p.m. to

8:00 p.m. Customers have responded by shifting their usage patterns, and they continue to adapt to this new, shorter period; gradualism supports leaving it in place. The previous on-peak hours of noon to 7 p.m., introduced on July 1, 2006 in Decision No. 68645, were in place for 11 years before they were eliminated and frozen for legacy solar residential customers in August of 2017.

Q. WHY WOULD CHANGING THE ON-PEAK HOURS CAUSE A BROAD RANGE OF BILL IMPACTS?

A. Customers consume varying amounts of energy during the on-peak and off-peak periods due to individual lifestyles and circumstances. As a result, reducing the number of on-peak hours would result in different levels of bill impact across residential customers. This was evident in the percent change included in Schedule H-4 filed with APS's application in the 2015 Test Year rate case.

To complete the proof of revenue, customer usage during any proposed on-peak and off-peak periods would need to be collected, and then the level of costs recovered in each window would need to be spread over the levels of usage that were collected, also referred to as the billing determinants. As the levels of usage in different hours would differ from those reflected in the 3:00 p.m. to 8:00 p.m. window, spreading these costs to derive the rates would change the on-peak and off-peak pricing ratios. Any ratio change to on-peak and off-peak pricing will cause customers with usage patterns different from the class average to experience a wider range of possible impacts from the calculated average percent change for the class.

In the past 40 years, APS has only made three changes to the hours used for on-peak pricing in residential rates. Because of these complexities, APS does not support changing the on-peak hours set in the last case.

Q. HOW WOULD A CHANGE TO THE ON-PEAK HOURS COMPLICATE INFORMING CUSTOMERS OF THEIR MOST ECONOMICAL RATE?

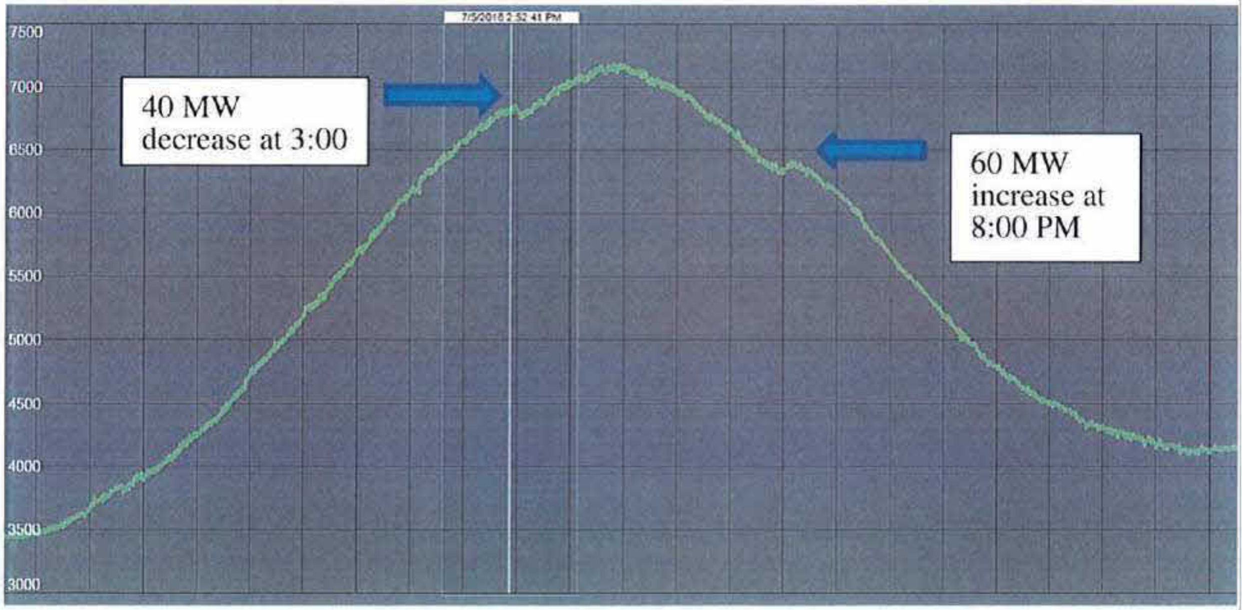
A. APS has continued to improve the online rate comparison tool that customers may use to inform their rate selections, such that it precisely calculates and displays the amount the customer would have paid on all other eligible rates. One effort in moving to this level of precision was introducing a tool that leveraged billing usage data instead of hourly interval data. Not only is the tool used for online comparison, it also provides monthly pro forma billing on customer electric bills, thereby advising customers whether they would save money on an alternative rate, and of the annual savings they could achieve in switching rates if they are not already enrolled in their MEP. Because the data is the same as what is used to bill the customer, there is never a variance in these calculations.

By comparison, the Company would not be able to use billing data if a new on-peak period were introduced until 12 months of actual customer billing data reflecting the on-peak period was collected. Monthly pro forma billing and the online rate comparison tool would not have the same level of precision that we have worked to achieve as a result.

Q. ARE CUSTOMERS ADJUSTING THEIR USAGE TO RESPOND TO THE CURRENT 3:00 P.M. TO 8:00 P.M. ON-PEAK HOURS?

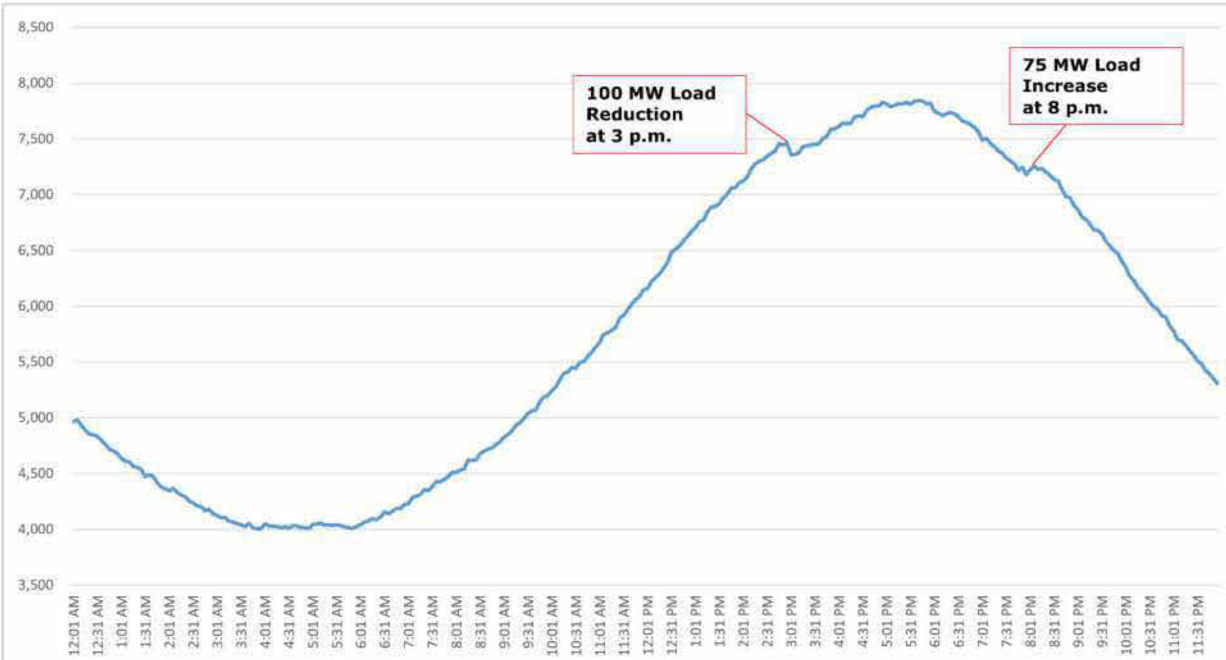
A. On July 5, 2018, at 3:00 p.m., APS saw a 40 MW reduction in actual system load, followed by a 60 MW increase at 8:00 p.m. (Figure 1)

Figure 1. Rate Impact on Customer Demand – July 5, 2018



As customers have continued to adapt to these hours, more significant shifting has occurred. The more recent graph below (Figure 2) demonstrates that even on the day that APS experienced its record peak system load, July 30, 2020, and temperatures reached 118 degrees, customers were still responsive to the 3:00 p.m. to 8:00 p.m. price signal. Even with more customers working from home due to the pandemic, the data demonstrates that customers are shifting their usage to align with the on-peak hours. Customers reduced their consumption at 3:00 p.m. by an even greater extent than 2018 as APS observed a 100 MW reduction in system load and a corresponding increase of 75 MW at 8:00 p.m.

Figure 2. Rate Impact on Customer Demand – July 30, 2020



Q. SOLAR ENERGY INDUSTRIES ASSOCIATION (SEIA) WITNESS KEVIN LUCAS PROPOSES A FOUR-MONTH SUMMER SEASON. DOES APS SUPPORT THIS RECOMMENDATION?

A. No. APS does not support shortening its existing six-month summer rate period for residential rates, which runs from May through October. Although generation capacity is typically planned to meet the system load in the four core summer months, APS basically has three seasons: the four core summer months, two or three shoulder summer months, and five or six non-summer months. The weather and loads during the two or three shoulder summer months (April, May, and October) can vary. Nevertheless, they typically require significant air-conditioning as temperatures often reach 100 degrees or more, especially in May and October. Further, while the overall load level for the shoulder months is lower than the core summer months, their daily load shape patterns more closely resemble the core summer months than the non-summer months. Because APS is proposing to simplify residential rates and bills, as recommended by numerous parties, the

Company does not support changing the existing six-month summer and non-summer seasons.

Q. WHAT DID RUCO PROPOSE IN ITS NEW OPTIONAL TOU RATE FOR ON-PEAK AND OFF-PEAK PRICE RATIOS?

A. RUCO proposes that the on-peak price should be over three times the off-peak price, when the existing R-TOU-E rate is currently two times the off-peak price.[2] RUCO asserts that a higher peak-to-off-peak price ratio will encourage customers to shift more load to off-peak hours.

Q. DO YOU SUPPORT RUCO'S PROPOSAL?

A. No. While higher TOU price ratios will always create more incentive for load shifting, the price ratios must also accurately reflect the cost of service. Otherwise, as customers shift load to off-peak hours, their bill savings will not be commensurate with utility cost savings, and as a result, some of the bill savings will have to be funded by other customers. The current on-peak price for rate R-TOU-E is approximately two times the off-peak price, which is reflective of cost of service. Further, adding a second optional TOU rate adds more complexity rather than further simplifying residential rate options.

Q. PLEASE EXPLAIN.

A. As shown in Table 3 below, the proposed charges for residential rate R-TOU-E reflect a peak-to-off-peak price ratio of 2.17 for the total bundled rates, which is similar to the ratio for the current rates. However, because the TOU prices predominately reflect temporal differences in generation capacity and energy costs, the price ratios for the proposed unbundled generation rates are more important to the rate design than the bundled amounts. As shown, the peak-to-off-peak price ratios for the unbundled generation rates is 3.01.

[2] RUCO Direct Testimony of Frank W. Radigan at 14-15 (Oct. 9, 2020).

Q. DO THESE PRICE RATIOS REFLECT THE COST OF SERVICE?

A. Yes. The design of TOU prices can be approached from several perspectives. The price ratios can reflect the embedded cost of service or they can be informed by market prices, avoided costs or other factors. Table 4 provides the total generation cost of service, which includes both capacity and energy costs, from each of these perspectives. The information includes the cost per kWh for on-peak hours and off-peak hours, and the ratio of the two. As shown, the peak-to-off-peak "cost ratio" is 2.28 from an embedded cost-of-service perspective, 2.26 from a market cost perspective, and a range of 1.78 to 2.12 for years 2018 to 2023 respectively from an avoided cost perspective. Each of these cost ratios is below the 3.01 unbundled generation price ratio reflected in the rates.

Q. HOW WERE THE CURRENT TOU PRICES DERIVED?

A. The current price ratios for rate R-TOU-E were thoroughly analyzed and debated in APS's last case and ultimately agreed to by Settling Parties, including RUCO. They not only reflect cost of service, but also result in a targeted level of bill savings for customers with rooftop solar. RUCO's proposal would move backwards on the important balanced results from the last rate case.

Q. WOULD RUCO'S PROPOSAL CREATE VARYING CUSTOMER BILL IMPACTS?

A. Yes. Several parties have commented on the need to more accurately communicate the expected rate impacts for specific customers in a rate case, rather than merely stating the class average impact. APS agrees. In addition, in order to keep the bill impacts for most customers close to the average, APS proposes minimal, strategic changes in its rates and opposes changes that would result in increased variability in rate impacts across the residential class. APS opposes RUCO's proposal to introduce a new TOU rate option and to change the on- and off-peak ratio because, among other reasons, it adds more complication than simplification and, if adopted for the existing R-TOU-E rate, would have the effect of significantly increasing the variability of rate impacts for individual residential customers.

Q. WHAT DO YOU RECOMMEND FOR RATE R-TOU-E?

A. I recommend keeping the TOU price ratios for rate R-TOU-E at the levels reflected in APS's proposed rates, which is, again, consistent with the current ratios. RUCO's new optional TOU rate proposal for an over 3:1 <u>bundled</u> price ratio would require a much higher price ratio for the unbundled generation charges or including a much higher level of distribution grid costs recovered in the on-peak price. Neither result is cost based. In addition, RUCO's proposal disrupts the balance of solar benefits agreed to in the last rate case and would cause disparate bill impacts amongst customers. For these reasons, RUCO's proposal for a new optional TOU rate should be rejected.

Table 3. Rate R-TOU-E Proposed Charges

Bundled Rates

	summer	winter	Average
kWh – on	0.24823	0.23552	
kWh – off	0.11122	0.11122	
kWh - super off		0.03294	
Price ratio on/off	2.23	2.12	2.17

Unbundled Generation Rates

	summer	winter	Average
kWh – on	0.20213	0.18942	
kWh – off	0.06512	0.06512	
kWh - super off		0.00736	
Price ratio on/off	3.10	2.91	3.01

Table 4. Generation Cost of Service for Rate R-TOU-E

	On-peak $ per kWh	Off-peak $ per kWh	on/off Ratio
Embedded Cost	0.1569	0.0687	2.28
Market Cost Ratio			2.26
Avoided Cost			
2018	0.0361	0.0203	1.78
2019	0.0344	0.0174	1.97
2020	0.0334	0.0183	1.83
2021	0.0373	0.0200	1.87
2022	0.0418	0.0221	1.89
2023	0.0489	0.0230	2.12

Sources:
Embedded Cost - Rate Case Cost of Service Study
Market Cost - CAISO EIM prices 2017
Avoided Cost - APS PURPA Avoided Cost Filing 2018

Q. APS ASSESS THE PROPOSED RATE DESIGN IN RUCO'S NEW OPTIONAL TOU RATE PROPOSAL?

A. Yes. As I mentioned previously, APS does not support adding an additional TOU rate because it adds complication, rather than simplification of APS's residential rates. In addition, APS evaluated the proposed rates and charges in RUCO's new optional TOU rate and found that the rate is not designed to be cost neutral with the existing R-TOU-E rate and would potentially result in a substantial change in customer impacts. If the new rate is adopted and properly addressed in a proof of revenue context, the rate would need to be redesigned to be revenue neutral, otherwise it would create a large cost shift to residential customers on other rates.

Specifically, RUCO witness Radigan proposes the creation of an additional TOU rate that includes a $15 basic service charge, a $0.07/kWh off-peak energy charge, and an on-peak energy charge of $0.25/kWh. Although the proposal does not explicitly reflect a super off-peak charge, APS compared the proposal with APS's proposed super off-peak rate using RUCO's testimony that supports retaining the super off-peak charge. To assess the impacts of this rate, customers billed under the R-TOU-E (Saver Choice) rate were rebilled under RUCO's proposed charges. Table 5 below highlights that this proposal results in a revenue deficiency of roughly $150 million, which would either require a significant redesign to be revenue neutral or would have to be spread across other rates to achieve the revenue requirement with anticipated migration to this below cost rate. RUCO's proposed additional TOU rate design not only recovers $150 million less than APS's proposed R-TOU-E rate, it also recovers approximately $100 million less than needed to support the rate decrease reflected in RUCO's proposed revenue requirement. The rate would not only introduce a cost shift, but it would also create a broad range of bill impacts across customer and rate classes.

Table 5. Proposed TOU Rate Comparison

Charge	Proposed Billing Determinants	Proposed TOU-E Rate ($/unit)	Proposed Revenue ($)	Proposed Billing Determinants	Proposed RUCO Rate ($/unit)	Proposed Revenue ($)		
TOU-E								
Summer - Days	68,531,326	0.437	29,948,189	68,531,326	0.500	34,265,663		
On-peak kWh	625,408,611	0.24823	155,245,180	625,408,611	0.25000	156,352,153		
Off-peak kWh	2,578,508,973	0.11122	286,781,768	2,578,508,973	0.07000	180,495,628		
Billed kWh, Revenue	3,203,917,584		471,975,137	3,203,917,584		371,113,444		
Winter - Days	69,826,575	0.437	30,514,213	69,826,575	0.500	34,913,288		
On-peak kWh	277,272,412	0.23552	65,303,198	277,272,412	0.25000	69,318,103		
Off-peak kWh	1,416,344,190	0.11122	157,525,801	1,416,344,190	0.07000	99,144,093		
Spr Off-peak kWh	231,616,037	0.03294	7,629,432	231,616,037	0.03294	7,629,432	RUCO	582,118,360
Billed kWh, Revenue	1,925,232,639		260,972,645	1,925,232,639		211,004,916	TOU-E	732,947,782
Annual Total	5,129,150,223		**732,947,782**	5,129,150,223		**582,118,360**	Difference	**(150,829,422)**

Q. DOES APS SUPPORT FEA WITNESS AMANDA ALDERSON'S PROPOSED CHANGES TO RESIDENTIAL RATES?

A. No. FEA witness Alderson disagrees that demand charges should be used year-round and suggests that R-2 (Saver Choice Plus) should have a demand charge billed only during the summer season. In addition, FEA witness Alderson encourages a stronger differential between winter and summer energy rates on R-TOU-E and R-2.

Q. EXPLAIN YOUR CONCERNS ABOUT FEA'S PROPOSAL?

A. FEA witness Alderson's proposal to impose the demand charge only in the summer and to widen the spread of seasonal energy charges on R-TOU-E works against the underlying premise of minimizing a wider range of bill impact. By capturing only demand revenues in the summer months, the additional winter demand revenue would have to be collected only during the summer months, causing a dramatic increase in the demand charge or other rate components. This will cause customers to experience a broad range of bill impacts based on different levels of energy consumption and demand.

Similarly, changes to introduce more seasonality in R-TOU-E would result in higher summer energy rates and lower winter energy rates. In the winter months, customers who have selected R-TOU-E get the benefit of significantly discounted energy during the super off-peak period, which serves as a method of introducing seasonality into this rate.

Q. DO THE BASIC SERVICE CHARGES PROPOSED RECOVER ALL FIXED COSTS ASSOCIATED WITH PROVIDING SERVICE TO RESIDENTIAL CUSTOMERS?

A. No. The current basic service charges are well below the actual costs classified as customer charges in Attachment LRS-3DR filed with APS witness Snook's direct testimony. Customer charges are those that do not vary with the volumetric consumption of energy. These costs include the cost of the meter, monthly reading of the meter, billing the customer each month, and other customer service-related costs.

An example of a customer service expense would be staffing the Customer Care Center to respond to questions that customers may have. This service is equally available to all customers and is not influenced by the amount of energy consumed.

Q. WHAT ADJUSTMENTS DOES APS PROPOSE TO THE BASIC SERVICE CHARGE IN THIS CASE AND WHAT METHODOLGY WAS USED?

A. APS proposes to increase the existing residential basic charges on an equal percentage across all rates in order to avoid variability in impacts across rates.

Q. DOES APS SUPPORT SWEEP AND WRA'S PROPOSED BASIC SERVICE CHARGE FOR ALL RESIDENTIAL RATES? IF NOT, PLEASE EXPLAIN WHY NOT.

A. No. Table 6 below illustrates the amount it costs per residential customer to provide these services as shown in Attachment LRS-3DR filed with APS witness Snook's Direct Testimony. Also shown are the proposed basic service charges for each residential rate as filed in the application and those which were proposed by SWEEP and WRA witness Brendon Baatz. Contrary to the suggestion Mr. Baatz makes in testimony that APS is proposing to collect the entirety of its proposed revenue increase through increases to the basic service charges (SWEEP and WRA Direct Testimony of Brendon J. Baatz at 27 (Oct. 9, 2020)), APS's proposal simply increases them at the same average increase level, roughly 2.3% to 2.4%, to minimize the range of bill impacts to customers. Table 4 clearly illustrates that even at current levels, each basic service charge is below cost for all but one residential rate. If SWEEP and WRA's proposal were adopted, this would reduce the level of recovery in the basic service charge to be consistently less than half of the costs that basic service charge is theoretically intended to recover.

Table 6. Proposed Basic Service Charge Comparison

Residential	Customer Charge			SWEEP Proposal	
Rate	Cost	Proposed Rate	% COS	Proposed Rate	% COS
Legacy Solar (Energy)	$ 36.27	$ 16.06	44.3%	$ 8.03	22.1%
Legacy Solar (Demand)	$ 35.82	$ 20.01	55.9%	$ 8.03	22.4%
R-Solar (TOU)	$ 35.69	$ 13.29	37.2%	$ 8.03	22.5%
R-Solar (Demand)	$ 35.64	$ 13.29	37.3%	$ 8.03	22.5%
R-Basic (0-600 kW)	$ 17.92	$ 10.25	57.2%	$ 8.03	44.8%
R-Basic (601-999 kW)	$ 18.14	$ 15.36	84.7%	$ 8.03	44.3%
R-Basic (1000+ kW)	$ 18.58	$ 20.47	110.2%	$ 8.03	43.2%
R-TOU-E	$ 18.27	$ 13.29	72.7%	$ 8.03	43.9%
R-Demand	$ 18.64	$ 13.29	71.3%	$ 8.03	43.1%

Q. DOES APS AGREE THAT A UNIFORM BASIC SERVICE CHARGE WOULD BE APPROPRIATE?

A. No. As Table 6 above illustrates, there are two variations in the customer-related charges for residential customers. Legacy solar customers receive an additional production meter to measure solar energy, and so the cost to serve this portion of their service is higher as a result. Non-legacy solar customers are eligible for any TOU rate offered to residential customers without solar so the allocation of costs to that rate does not reflect the additional meter as it does not apply for all customers in their class. If the basic service charge were 100% cost based, a rate of approximately $35 for residential solar customers and approximately $18 for residential non-solar customers would be appropriate.

The basic service charges currently in place were developed during the last rate case settlement based on intervenor input and feedback so they reflect the interest of a variety of parties. Additionally, any changes to these charges that differs from the average percentage of increase being applied would result in a different level of bill impacts experienced by customers. For customers who consume less energy, an increase to the basic service charge represents a larger percentage of the bill than it does to a customer who consumes more.

Q. DOES APS AGREE WITH STAFF'S RECOMMENDATION TO COMBINE R-XS AND R-BASIC AND APPLY THE ENERGY CHARGES IN BLOCKS?

A. No. Staff's recommendation would introduce a rate similar to the E-12 inclining block rate that was frozen in Decision No. 76295. In APS witness Charles Miessner's Direct Testimony from the 2016 rate case, he explains the reasons supporting the decision to eliminate the inclining block structure. An excerpt from his testimony is provided below. These reasons remain valid today and demonstrate why APS does not support Staff's proposed inclining block rate (Direct Testimony of Charles A. Miessner, Docket No. E-01345A-16-0036, at 23 (June 1, 2016)):

> Customers with higher than average monthly usage pay a rate that is higher than average; customers with lower usage pay a rate that is lower than average. Therefore, the incentive for customers to adopt technologies that reduce energy usage varies considerably for each customer.
>
> In addition, this inclining block rate structure does not reflect cost of service – the cost of service is not higher for homes with higher monthly kWh usage on a per unit basis. A large car may consume more gas, but the cost per gallon is the same for all cars (for the same octane product).
>
> The existing two-part time-of-use energy rates are an improvement over the inclining-block rate because they incent technologies that focus on reducing energy consumption during on-peak hours. However, this is still only a partial improvement because, like the inclining block rate, the time-of-use energy rates fail to provide any incentive for reducing kW demand, which is a key driver of infrastructure capacity costs.

Q. DEMAND RATES CONTINUE TO FACE CRITICISM FROM VARIOUS PARTIES. WHY DOES APS CONTINUE TO SUPPORT THESE RATE STRUCTURES?

A. Demand rates continue to send the appropriate price signal and provide the most precise alignment between the rates customers pay and the costs that are incurred to serve them. As a result, demand rates offer customers a meaningful opportunity to save money when they choose to respond to these price signals by conserving on-peak usage.

Customer-related costs like metering, meter reading, billing and customer service continue to be recovered through a basic service charge, and costs that vary with increases and decreases in volumetric consumption, such as fuel, remain collected through on-peak and off-peak energy charges. The demand charges recover costs associated with the distribution and generation capacity needed to serve a customer's load, which is why APS's demand rates only apply to the times when system load is highest, the on-peak period. The peak hour of usage during this time reflects the amount of energy APS should be equipped to serve for a specific customer during the on-peak period.

In addition, the demand rates are entirely voluntary. APS's rebuttal proposal brings back a flat-rate option for all eligible customers. Combined with the TOU options, customers now have complete freedom to choose the rate structure that best fits their lifestyle. Customers who voluntarily enroll in demand rates can benefit from lower energy prices at all hours by managing the amount they consume during the five on-peak hours during weekdays, excluding weekends and holidays.

In Arizona, the summer climate and cooling needs provide ample opportunity for customers to pre-cool their homes during the hours leading up to the on-peak window, helping them lessen the level of peak demand and achieve deeper savings.

Some customers have invested in smart thermostats, load controllers, and/or other demand response devices to increase their savings on demand rates. APS believes strongly that these rates should continue to be offered as they have been for nearly 40 years in Arizona on a voluntary basis to customers who elect to take advantage of managing their on-peak usage. This preserves the customer's freedom to choose and helps to avoid or postpone the need to invest in additional generation resources.

Q. WOULD SWEEP AND WRA'S RECOMMENDATION TO FREEZE DEMAND RATES BENEFIT CUSTOMERS?

A. No. APS disagrees with SWEEP and WRA's recommendation to freeze three-part rates and phase them out. More than 307,000 APS customers have voluntarily chosen this rate as their preferred service plan as of September 30, 2020, many of whom are experiencing savings as a result. Voluntary enrollment in demand rates has increased from 12% at the time the most recent residential rates were approved in August 2017, to 27% as of the end of September 2020. This serves as further support that both customer usage patterns and evolving technologies allow many to benefit from this rate structure.

SWEEP and WRA witness Baatz referred to an article authored by Dr. Ahmad Faruqui in 2013 that suggests TOU pricing yields significant load reductions (Baatz at 15). While APS embraces the value that time-variant pricing reflects, it is not a complete toolbox. Further, Dr. Faruqui also wrote in May 2018 for Public Utilities Fortnightly that, "The best rate is going to be a modern three-part rate for all customers." (Public Utilities Fortnightly, "Future of Rate Design," May 2018, p. 35.) In this same article, Dr. Faruqui further elaborates that "…rate design needs to serve multiple objectives, including equity, bill stability, revenue stability, and customer satisfaction." (*Id.*, p. 36.)

Q. WERE THE DEMAND RATES THAT WERE APPROVED IN APS'S LAST CASE A SIGNIFICANT DEPARTURE FROM APS'S PRIOR RATE PLANS AS SWEEP AND WRA WITNESS BAATZ ASSERTS?

A. No, they were actually quite similar in structure. Prior to the rates introduced in August 2017, APS offered residential customers choices among a basic rate, a TOU rate, and a demand rate, the same rate structures offered today. The old and new rates were very similar in structure, although the on-peak hours were reduced from seven hours to five hours and the differential in winter and summer rates were adjusted in 2017 to minimize summer bills during the cooling season.

Q. DURING THE RATE TRANSITION IN THE LAST CASE OR ANYTIME THEREAFTER HAS APS INVOLUNTARY PLACED ANY CUSTOMERS ON A DEMAND RATE?

A. No. While APS had proposed in its original application filed in 2016 to migrate residential customers to their MEPs, through the settlement process the parties agreed that APS should not move customers to their MEP. The settling parties agreed, and the Commission approved a plan that preserved customer choice by migrating customers to the rate most like the one on which they were already enrolled instead of the MEP unless the customer proactively selected a different type of rate plan. No customers were placed on a demand rate without voluntarily choosing one.

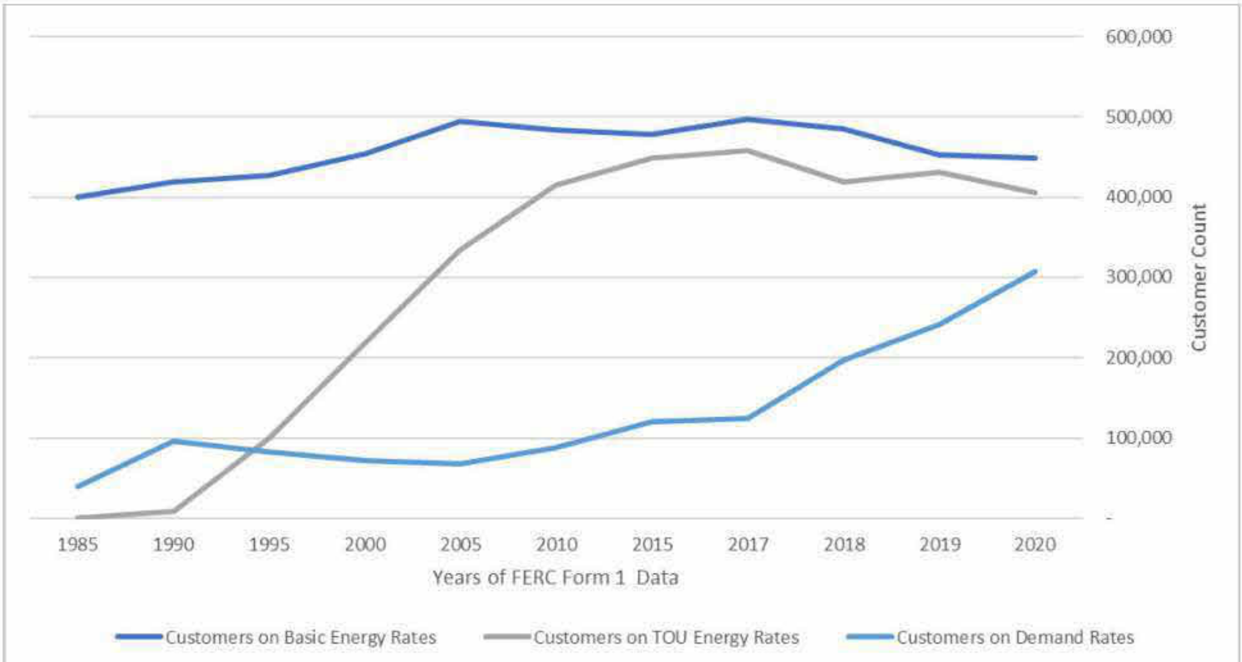
Q. HOW LONG HAS APS OFFERED DEMAND RATES FOR RESIDENTIAL CUSTOMERS?

A. APS has offered voluntary demand rates to customers for almost 40 years.

Q. HOW MANY APS CUSTOMERS HAVE SELECTED A DEMAND RATE?

A. The graph below shows the number of residential customers who have enrolled in a demand rate since 1985, and that APS has had healthy levels of adoption of residential demand rates since. The three rate structures described previously are consistent through this time frame as well.

Figure 3. Residential Rate Enrollment Levels, 1985-2020



Q. IS APS REQUESTING MANDATORY RESIDENTIAL DEMAND CHARGES IN THIS RATE CASE?

A. No. Although Staff witness Ralph Smith states that APS is requesting mandatory demand charges for residential customers (Staff Confidential Direct Testimony of Ralph C. Smith, Docket No. E-01345A-19-0236, at 93 (Oct. 2, 2020)), this is not the case. APS proposes in its rebuttal testimony to expand customer choice to allow all eligible customers, irrespective of their usage, to select a flat, a TOU or a demand rate. As discussed in the testimony of APS witness Whiting, APS recognizes that customer choice is important and that customers choose rates based on a variety of factors, not just cost. Our goal in this case is to simplify the rates and make it easier for a customer to choose the rate that works best for their lifestyle.

Q. DOES APS HAVE DEMAND FOREGIVENESS OR ANY DEMAND PROTECTION FEATURE THAT PROTECTS CUSTOMERS FROM ONE-TIME UNUSUAL DEMAND EVENTS? IF SO, PLEASE EXPLAIN?

A. Yes. APS's residential demand rates include a demand limiter feature that protects customers from unexpected and unusual increases in demand. In instances where the ratio between the customer's average demand to peak demand falls below 15%, the demand limiter adjusts the kW level downward to ensure that a load factor below 15% is not experienced. If a customer were to experience a dramatic increase in their highest on-peak hour during the month, this feature is designed to limit the bill impact that might accompany that higher level of demand. This demand limiter feature was added in APS's last case and has been in place since August of 2017, with no changes recommended at this time.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THE DEMAND LIMITER FEATURE FUNCTIONS IN REAL LIFE?

A. Let's take a look at an example of a customer who had a June bill with 30 days in the billing cycle, 1,000 kWh of usage, and a meter read demand of 15.0 kW. The load factor based on the customer's actual usage was roughly 9%. Because the demand limiter is designed to kick in any time the load factor falls below 15%, the billing system would reduce the demand such that the customer would be billed only 9.2 kW calculated using the following formula:

Max Billed kW = 1,000 kWh / (15% * 30 days * 24 hours)

Q. FOR A CUSTOMER ON R-3, WITH A SUMMER KW CHARGE OF $17.438, THE DEMAND REDUCTION OF 5.8 KW SAVED THE CUSTOMER $101.14 THAT MONTH. HOW OFTEN DOES THIS PROTECTION BENEFIT CUSTOMERS?

A. During the Test Year, the demand limiter reduced the demand charge for nearly 88,000 bills, or approximately 3.25% of bills for customers billed on a demand rate. These reductions represented $1.058 million in customer savings.

Q. STAFF WITNESS DAVID DISMUKES SUGGESTS ELIMINATING SEASONAL DEMAND CHARGES AND TIME-VARIANT ENERGY CHARGES ON R-2 AND R-3. WOULD THIS HELP CUSTOMERS?

A. No, quite the opposite is true. In his rate design testimony, RUCO witness Radigan states, "Phoenix's average high temperatures in summer are the hottest of any major city in the United States. Not surprisingly APS is a summer peaking utility…" (RUCO Direct Testimony of Frank W. Radigan, Docket No. E-01345A-19-0236 at 3 (Oct. 9, 2020)). Time variant energy charges allow customers to benefit by shifting usage to lower cost periods. As the summer season is quite different than the winter load in Arizona, having prices that differentiate seasonally more accurately reflects the cost to serve customers. Regional market scenarios, such as winter mid-day negative pricing, further support why seasonality is important in the ratemaking process.

Q. WHY DOES APS DISAGREE WITH STAFF'S RECOMMENDATION TO CALCUATE THE DEMAND COMPONENT OF ITS RESIDENTIAL DEMAND RATE BASED ON THE CUSTOMER'S HIGHEST MONTHLY PEAK HOUR?

A. In addition to the financial impacts untimed demand would have on customers, there are several other drawbacks. First, it undermines conservation. Untimed demand takes away the on-peak price signal that encourages customers to conserve energy when system resources are more limited and more costly to provide. Second, it is also overly punitive to customers because it requires them to manage their usage around the clock for 168 hours per week instead of 25 hours per week, during solely the on-peak hours. If customers enrolled in R-2 and R-3 during the Test Year had their demand billed based on Staff's approach, the highest hour of the month not the highest on-peak hour, the amount of kW subject to the demand charge would have been an additional 1,739,564 kW or 120% of the amount actually billed during the Test Year.

Q. STAFF OPPOSES THE ADDITION OF A SUPER OFF-PEAK PERIOD INTO RESIDENTIAL DEMAND RATE R-3 (SAVER CHOICE MAX). DOES APS STILL PROPPOSE THIS IN REBUTTAL?

A. Yes. The super off-peak feature offers substantial potential benefits to our customers and APS continues to support adding this feature to R-3 (Saver Choice Max). By encouraging customers to use energy during a time of day when costs are lower, and in some instances negatively priced, customers can experience immediate bill savings. This discounted period can be used to pre-heat homes or run pool pumps to take advantage of additional savings. Since this feature was introduced, the amount of energy consumed during the super off-peak period by residential R-TOU-E customers increased from 17.8% of total energy use to 18.7%. While 1% may not seem significant, that represents 52,163 more MWh consumed by R-TOU-E customers compared to the prior ET-2 time-of-use rate that did not include a super off-peak price signal. Thus, while APS understands that this could be construed as making this rate slightly more complicated, the potential benefits to customers outweigh that concern.

Q. IF STAFF'S PROPOSAL WERE ADOPTED, WHAT WOULD BE THE IMPACT TO CUSTOMERS?

A. Staff witness Dismukes recommended a number of changes to residential rate design that have been addressed individually throughout my testimony, including combining some rate classes, eliminating seasonal demand charges and TOU energy charges for demand rates, a revised on-peak window, and uniform basic service charges. If all of these changes were incorporated, the range of bill impacts experienced by customers would be quite broad. Table 7 below illustrates the range of base rate impact on residential customers from Staff's proposal.

Table 7. Base Rate Impacts from Staff Recommendations

Staff Recommendations

% Impact Range	% Customers
<=-10.00%	0%
-5.00 to -9.99%	3%
-2.50% to -4.49%	15%
0 to -2.49%	5%
0.01 to 2.50%	31%
2.51 to 5.00%	16%
5.01% to 7.50%	13%
7.51% top 10.00%	9%
10.01% to 15.00%	4%
15.01 to 20.00%	1%
20.01 to 25.00%	1%
25.01 to 50.00%	1%
>50.00%	0%

Q. ARE THERE OTHER POINTS THAT YOU'D LIKE TO CORRECT OR CLARIFY REGARDING RESIDENTIAL RATE DESIGN?

A. Yes. When referring to the residential rates designed and implemented in Decision No. 76295, Staff witness Dismukes suggests that APS's rate design changes were intended to migrate customers from two-part rates to three-part rates and that 58,984 customers were involuntarily transitioned to a different rate plan as of

December 2019. Staff witness Dismukes is mistaken. It is important to note that the rate migration which took place during the first quarter of 2018 was not intended to and did not move customers to different rate structures. As explained earlier, customers were transitioned or migrated to new rates that were most like the rates they were already enrolled in. Customers on energy-only rates moved to an energy-only rate. Customers who had selected a TOU energy rate were migrated to a TOU energy rate. Customers who had chosen a demand rate were migrated to a demand rate. This migration was consistent for all customers except those who proactively contacted APS in response to the customer education and outreach materials and voluntarily chose a different rate.

Q. HAS OR IS APS OVER-EARNING BECAUSE NOT ALL CUSTOMERS SELECT THEIR MEP?

A. No. The rates and proof of revenue that were approved in the last rate case were not designed on the assumption that every customer would select his or her MEP. In the rate design process, APS assumed that if customers could experience at least 10% in annual bill savings or $10 monthly, whichever was greater, then they would choose to enroll in their MEP. Based on that assumption and our history with optional rates,[3] APS projected that only approximately 53% of residential customers would be on their MEP. This assumption (that approximately 53% of customers would be on their MEP) was used to design rates in the proof of revenue to collect the approved revenue requirement. If APS had designed rates based on 100% of customers on their MEPs, the level of increase in the rates and charges needed to achieve the revenue requirement would have been much greater. As of September 2020, 49.6% of residential customers are enrolled in their MEP, roughly 3% less than this estimate.

[3] In the 2015 Test Year, 47.7% of customers were on their MEP.

Q. TO BE CLEAR, DID APS ASSUME ANY LEVEL OF RATE MIGRATION TO ASSUME MORE OR FEWER CUSTOMERS MOVED TO THEIR MEP IN ITS PROOF OF REVENUE IN THIS CASE?

A. No. APS's proposal does not estimate any rate migration from the Test Year amounts.

Q. HOW HAS THE R-TECH PILOT RATE PERFORMED SINCE IT WAS INTRODUCED IN THE LAST RATE CASE?

A. There continues to be a relatively low rate of adoption on the R-Tech rate, with 55 customers currently enrolled. One contributing factor to the enrollment level may be the cost of battery storage versus the expectation of what the cost to a residential consumer would be after this pilot rate was approved. When the R-Tech rate was developed during the last rate case, it was done so in a collaborative effort with feedback from multiple interested parties, including SEIA. The goal of the design was not intended to incentivize the procurement of specific technologies, but rather to complement different technologies, such as smart thermostats, storage devices, electric vehicles, etc., by allowing customers to benefit from energy savings when those technologies were used effectively in reducing load during higher cost periods.

Q. WHY DOES THE R-TECH RATE INCLUDE AN OFF-PEAK EXCESS DEMAND CHARGE IF THE INTENT IS TO DISCOURAGE USAGE DURING THE ON-PEAK HOURS?

A. Although SEIA witness Lucas suggests that an off-peak demand charge is not necessary, the off-peak excess demand charge was implemented as a protection against the creation of a new peak during the evening hours by allowing for the first 5 kW to warrant no demand charge with a much smaller charge assessed for demand above 5 kW. The reason for the higher on-peak demand charge and lower energy charges that SEIA claims are too complicated for a technology pilot rate was to allow customers who can use technology to manage their demand to achieve greater savings. As such, it is appropriate that this rate be designed to collect more demand revenue than other residential demand rates.

Q. WHAT IS YOUR OPINION OF SEIA'S PROPOSED VOLUMETRIC TECHNOLOGY TOU RATE INSTEAD OF R-TECH?

A. Conceptually, customers who invest in multiple energy management technologies can save more on rates designed with a demand charge because they typically include lower energy charges than TOU rates that lack a demand component. Energy management devices can further support customers in shifting usage outside of the on-peak hours, so the benefit derived from lower off-peak energy rates often makes this rate design a good complement. SEIA's proposed TOU technology rate is simply not a rate designed with proper price signals for technology.

Q. WHAT DOES APS PROPOSE TO DO WITH THE R-TECH PILOT RATE?

A. Although participation in the R-Tech rate has not approached the 10,000 cap, APS believes that the recently approved Residential Energy Storage Pilot, which provides participating customers with an incentive of $500/kW up to a maximum of $2,500 per home, may introduce additional participation in the rate and allow further evaluation of its performance. As such, APS agrees with Staff witness Dismukes' recommendation that the feasibility be reviewed in a future proceeding and would propose to continue monitoring R-Tech as this storage pilot is introduced to see if the desired objectives are achieved before redesigning the rate.

Q. STAFF WITNESS MATT CONNOLLY MAKES SEVERAL RECOMMENDATIONS TO IMPROVE THE RATE COMPARISON TOOL. DO YOU SUPPORT THESE CHANGES?

A. There are some recommendations that APS supports and is currently pursuing, and others that it disagrees with as unnecessary. For example, Staff witness Connolly suggests that a disclaimer be used to inform customers that the tool relies on forecasts that are based on average usage. This is not appropriate because the rate comparison tool uses actual customer historical usage to calculate what the bills would have been on each alternative rate plan. Staff further suggests that such a disclaimer also notify customers that the recommendations are based on normal weather patterns. Again, since the tool uses actual historical usage, this is not necessary. APS does support the recommendation to make sure customers are aware of the impacts of peak usage increases, and commits to enhanced and simplified customer education about the demand limiter mechanism. APS witness Whiting discusses in more detail the enhancements underway and those being evaluated to further support customer education and access to information on aps.com, in response to intervenor feedback.

Q. WHAT CHANGES WERE PROPOSED BY INTERVENORS IN RELATION TO RESIDENTIAL SOLAR RATE OPTIONS?

A. SEIA witness Lucas proposes to eliminate restrictions on the rate options available to solar customers, to eliminate the grid access charge (GAC), and to apply the demand limiter feature intended to limit the impact of sudden, unexpected increases in demand to customers with rooftop solar systems as well.

Q. DOES APS AGREE WITH THESE PROPOSALS? WHY OR WHY NOT?

A. APS is not supportive of the recommendations made by SEIA on the basis that each of these proposals would disproportionately benefit solar customers and shift costs to non-solar customers. The eligibility criteria requiring customers with new solar systems to select a TOU or demand rate is necessary to avoid creating an unsustainable cost shift to customers without solar. Solar customers on energy-only rates pay significantly less than their cost of service compared to non-solar customers on energy-only rates. APS witness Snook discusses the cost-shift issue in further detail in his testimony.

Similarly, the addition of a GAC for solar customers selecting R-TOU-E (Saver Choice) is necessary and appropriate to reduce some of the $1 billion cost shift from residential solar customers to other customers (Decision No. 75859 at 176 (Jan. 3, 2017), Decision No. 76295 at 24-27 (August 18, 2017)). The basis of this charge is that solar customers typically export energy generated by their systems that exceed the amount they consume during a time when APS does not necessarily need additional generation resources. This requires additional use of the distribution system when compared to non-solar customers. Additionally, the introduction of more than 100,000 residential solar systems causes the need for additional distribution level monitoring and voltage control, some of which is intended to be recovered through this charge. Based on these reasons, the addition of the GAC is appropriate.

Although SEIA witness Lucas suggests that this charge provides a disincentive over residential demand rates, demand charges are less likely to be avoided entirely than volumetric energy charges; therefore, more of these costs are recovered from solar customers who are served under demand rates. Lastly, if the demand limiter described earlier in this testimony were offered to solar customers, it would trigger four times as often, nearly 12% of the time as opposed to 3% of the time for non-solar customers.

Q. ARE SOLAR CUSTOMERS MORE LIKELY TO SELECT A DEMAND RATE BECAUSE OF THE GRID ACCESS CHARGE?

A. No. Based on the levels of enrollment taken from the 2019 FERC Form 1 filing shown in Table 8, most solar customers are selecting the R-TOU-E rate that includes a GAC.

Table 8. APS Customer Solar Customer Rate Selection (2019)

Rate	Count	%
R-TOU-E	12,506	74%
R-2	1,635	10%
R-3	2,676	16%

Q. WHY HAS APS NOT PROPOSED A RESIDENTIAL ELECTRIC VEHICLE CHARGING RATE OR AN EVENING SUPER OFF-PEAK PERIOD FOR CHARGING?

A. APS can appreciate the recommendation made by SWEEP and WRA witness Baatz that an evening super off-peak period would benefit the charging of electric vehicles, but the Company believes the R-3 or Saver Choice Max rate accommodates this purpose well. The proposed summer off-peak price for R-3 is $0.05399, which translates to less than $0.50 per gallon of gas if charging is limited to the off-peak hours. When compared to SRP's Electric Vehicle Price Plan, the cost of charging an electric vehicle during off-peak hours on Saver Choice Max is consistently less in all periods, even less than SRP's EV super off-peak hours of 11 p.m. to 5 a.m., which are $0.0575 in the winter and $0.0611 in the summer.[4] To ensure customers are aware of the value this rate can offer for EV charging, APS is working to market this more specifically for this purpose to customers who are looking to acquire, or have already acquired, an electric vehicle and can charge during the off-peak hours.

Q. IS APS PREPARED TO INTRODUCE A BRING YOUR OWN DEVICE PROGRAM AT THIS TIME?

A. Staff witness Phillip Metzger recommends that a program of this nature belongs in either the Demand Side Management (DSM) or Renewable Energy Standard docket, and APS agrees with that approach.

[4] SRP Electric Vehicle Price Plan page: https://www.srpnet.com/prices/home/electricvehicle.aspx

Q. DID INTERVENORS OFFER ANY COMMENTS ON THE PROPOSED SUBSCRIPTION RATE PILOT?

A. Yes. Intervenors provided mixed feedback on the implementation of the subscription rate pilot program proposed in APS's application.

Q. WHAT IS APS'S POSITION NOW ON THE SUBSCRIPTION RATE PILOT?

A. APS is withdrawing its proposal for a subscription rate pilot. Please also see APS witness Whiting's testimony for additional information on the reasons for this decision.

V. <u>LIMITED-INCOME RATES AND PROGRAMS</u>

Q. WERE THERE ANY RECOMMENDATIONS CONCERNING LIMITED-INCOME PROGRAMS?

A. Yes. Both Wildfire witnesses filing testimony in this matter, Cynthia Zwick and John Howat, made recommendations to modify the eligibility criteria for the E-3 discount program as well as the amount of the discount applied to customer bills.

Q. DOES APS SUPPORT THE RECOMMENDATIONS BY WILDFIRE WITNESSES ZWICK AND HOWAT TO MODIFY THE ELIGIBILTY FOR THE E-3 PROGRAM?

A. Yes. APS understands that customers may be experiencing additional financial burden during this time and supports the recommendation to increase the eligibility criteria from 150% to 200% of Federal Poverty Level (FPL), which will have an estimated impact of an additional $21.357 million per year above the amount reflected in the Test Year. If approved by the Commission, this amount would be reflected in the accounting deferral order limited income costs requested by APS in its direct testimony and would be eligible for future recovery in APS's next rate case. If the deferral mechanism is not approved, this increase in program cost would need to be addressed in some other manner. APS witness Whiting elaborates further in testimony on support of this change.

Q. DOES APS SUPPORT THE RECOMMENDATIONS BY WILDFIRE WITNESSES ZWICK AND HOWAT TO INCREASE THE E-3 DISCOUNT?

A. APS is cautious about increasing the amount of the E-3 discount because it believes the current 25%, combined with the increased eligibility, strikes the right balance between providing support for this population and cost impacts on all other customers. Currently, APS's E-3 program provides eligible customers with a 25% monthly bill discount. This percent discount is substantially higher than the discount provided by other Arizona utilities. Thus, APS does not support the recommendation proposed by Wildfire witness Zwick to increase the discount from 25% to 30%, nor does APS support the alternative proposal by Wildfire witness Howat to implement a tiered discount ranging from 24.2% to 79.4%.

Q. WHAT IS THE MAGNITUDE OF THE FINANCIAL IMPACT OF THE RECOMMENDATIONS MADE?

A. APS understands the intent of the concept being proposed but does not support the proposal at this time due to concerns of added complexity and cost. Assuming Wildfire witness Howat's estimates are correct, that 114,941 APS customers would qualify for the discount program if the eligibility were increased to 200% of FPL, APS estimates that the cost of this proposal greatly exceeds the $59.2 million per year that he calculates (Wildfire Direct Testimony of John Howat, Docket No. E-01345A-19-0236, at 18 (Oct. 9, 2020).

To validate the cost, APS requested the percentage of E-3 participants that would qualify for each of the income tiers specified from the third party that processes applications and validates income eligibility. These results show that an estimated 34% of E-3 participants fall within the 0-75% of FPL that would receive a 79.4%

discount under the suggested approach. APS then applied the average bill for E-3 customers, $118.91 based on discounts applied during the Test Year, and calculated a 79.4% discount to the 39,080 customers that would qualify for that specific tier (34% of the 114,941 eligible participants). The Company determined that the 0-75% FPL tier alone results in an annual discount of $44 million. If one applies this same methodology to calculate the level of funding needed to fund the 76-125% of FPL tier, with an estimated 41% of E-3 applicants meeting that criteria, the result is another $30 million. In just these two tiers, the annual funding would be more than $74 million per year. APS estimates the annual impact of Wildfire witness Howat's entire tiered approach would cost more than $100 million annually. During the Test Year, the total funding of the discount program included $19.397 million, which means that if Wildfire witness Howat's recommendation were adopted, an additional $80 million per year would be needed. Again, APS believes the current 25%, combined with the increased eligibility, strikes the right balance between providing support for this population and cost impacts on all other customers.

Q. DO YOU AGREE THAT E-3 AND E-4 CUSTOMERS SHOULD BE EXEMPT FROM A RATE INCREASE AS WILDFIRE PROPOSES?

A. No. APS is not proposing to exempt E-3 and E-4 customers from any rate increase. However, by nature of the design of the discount program, they will experience a much smaller impact than the residential class. Because the discount is applied as a percentage of the bill, a 25% discount on E-3 and a 35% discount on E-4, the dollar amount of the discount will increase to scale with the change in rates. As a result, this group of customers will experience 65% to 75% of any rate increase applied to residential customers more broadly.

Q. WAS THE PROPOSAL TO INTRODUCE A DEFERRAL FOR COSTS TO SUPPORT THE DISCOUNT PROGRAM AND TO REFUND CREDIT CARD TRANSACTION FEES FOR E-3 AND E-4 CUSTOMERS OPPOSED?

A. No parties surfaced opposition to these two recommendations. The deferral proposal was supported by Wildfire witness Howat, and the credit card fee refund received support from Wildfire witness Zwick.

VI. <u>GENERAL SERVICE RATE DESIGN</u>

Q. EVGO PROPOSED A DEMAND FORGIVENESS FEATURE TO INCENT DC FAST CHARGING. WHAT ARE YOUR THOUGHTS ON THAT PROPOSAL?

A. As EVgo witness Thomas Beach mentions in his testimony, APS has been working informally on rate design concepts that would support and discount the demand charge for Commercial DC Fast Charging stations in the APS service territory (p. 6, line 7). The concept initially presented for input and feedback was to waive the first 100 kW, which would allow charging stations to avoid a portion of the demand charge while utilization of the stations increases.

Based on feedback from stakeholders, an additional option is currently being explored. This would introduce the demand limiter concept used in residential demand rates that adjusts the demand kW level downward to maintain a load factor of 15% or higher. Like any discount provided, funding must be explored. While EVgo witness Beach indicates that incenting electric vehicles benefits all customers because this is new and incremental load, APS's system is reliably designed with forecasted growth in mind; therefore EVgo should not avoid charges that other new customers would be obligated to pay. Initial thoughts are to consider recovering the discount amount through the DSM or REAC adjustor mechanisms, and the Advanced Energy Mechanism that APS witness Snook describes in rebuttal testimony may be an option as well.

Table 9 below illustrates the first year of costs needed to fund each discount proposal being considered. These results were based on applying each provision to 253 monthly electric bills for a sample population of DC Fast Charging stations APS currently serves. Given the desire to fund the discount through a DSM or clean energy program, participants would need to take service under a TOU rate schedule where applicable. Due to the fairly significant differences in the discounts APS is considering, none of which are currently reflected in the revenue requirement sought in this case, compared to EVgo's 10-year proposal, which is nearly four times the cost of the most significant discount being considered, APS believes additional collaboration, research, and design must take place before a concrete design is ready for filing.

Table 9. Informal DC Fast Charging Rate Design Options

	100 kW Forgiven	Load Factor Limiter Limiter - 15%	Load Factor Limiter Limiter - 20%	EVGO Proposal
E-32 XS	$ 21,994	$ 34,174	$ 38,536	$ 43,378
E-32 S	$ 9,691	$ 23,748	$ 25,551	$ 23,594
E-32 M	$ 90,171	$ 91,324	$ 127,813	$ 450,227
E-32 L	$ 102,956	$ 79,486	$ 127,726	$ 281,127
E-32 TOU M	$ 4,521	$ 4,158	$ 6,298	$ 13,070
E-32 TOU L	$ 36,396	$ 5,830	$ 14,422	$ 205,898
Total	$ 265,730	$ 238,720	$ 340,345	$ 1,017,294

VII. PRO FORMA ADJUSTMENTS

Q. DID ANY INTERVENOR SUPPORT APS'S PROPOSAL TO INCREASE FUNDING FOR CRISIS BILL ASSISTANCE?

A. Yes. Wildfire witness Zwick supports the increase of $1.25 million, which would bring the amount of available Crisis Bill Assistance to $2.5 million per year, and suggests that anyone living within 200% of FPL should qualify.

Q. DOES APS SUPPORT WILDFIRE'S RECOMMENDATION TO OPEN ELIGIBILITY FOR CRISIS BILL ASSISTANCE TO ALL INDIVIDUALS AT 200% FPL IRRESPECTIVE OF WHETHER THEY ARE EXPERIENCING A CRISIS SITUATION?

A. Because funding of this program is limited, APS believes the existing criteria to demonstrate financial hardship or a crisis to qualify for Crisis Bill funding is appropriate. The purpose of Crisis Bill funding is to provide additional support above and beyond what is provided in the E-3 Energy Support discount program, which provides customers with a 25% discount on their monthly bill. In addition, the changes APS has proposed to expand eligibility for its E-3 Energy Support discount program to all customers who meet the 200% FPL criteria will help address Wildfire witness Zwick's concerns.

Q. IS APS CHANGING ITS PROPOSAL REGARDING THIS PRO FORMA?

A. No. APS remains committed to its proposal to double the amount of Crisis Bill Assistance funding.

Q. DID ANY INTERVENOR RECOMMEND CHANGES TO THE BAD DEBT PRO FORMA?

A. No, and APS does not propose any at this time.

Q. WERE THERE ANY RECOMMENDATIONS CONCERNING THE ELIMINATION OF SEVERAL FEES IN SERVICE SCHEDULE 1?

A. No. There were no recommendations from other parties related to this change, in which APS proposes to eliminate certain fees and incorporate the costs of performing routine services required to connect or reconnect service within the overall cost of service.

Q. IS APS PROPOSING ANY CHANGES TO ITS PRO FORMA REGARDING THE ELIMINATION OF FEES?

A. APS will move forward by introducing methods that simplify the way we do business with our customers and will seek approval to waive the fees as previously described in direct testimony.

VIII. SERVICE SCHEDULE CHANGES

Q. DOES APS ACCEPT STAFF'S RECOMMENDATIONS REGARDING THE SERVICE SCHEDULE 9 ECONOMIC DEVELOPMENT DISCOUNT?

A. Yes. APS's proposal expands eligibility for rural customers to encourage economic growth, along with some modifications to conflict of interest provisions. Staff witness Metzger was supportive of the rural eligibility criteria change but proposed alternative language to replace the proposed conflict of interest reporting provisions. APS supports Staff's alternative recommended language.

Q. ARE THERE ADDITIONAL CHANGES TO THE SERVICE SCHEDULES THAT YOU WOULD LIKE TO RECOMMEND?

A. Yes. APS proposes to revise Service Schedule 1 to lengthen the amount of time its customers have to remit payment after a bill is issued from 14 days to 21 days.

Q. WHY DOES APS PROPOSE TO CHANGE THE NUMBER OF DAYS CUSTOMERS HAVE TO PAY THEIR BILLS?

A. APS makes this proposed change in order to align its practice more closely with other utilities and to improve customer satisfaction. The average across the industry for other investor-owned and municipal utilities is typically 19 days. Currently, APS offers customers 14 days to pay and proposes modifying Service Schedule 1 to offer 21 days instead to allow customers additional time they may need to remit payment. With APS currently in the fourth quartile of J.D. Power survey results specific to this category, the Company believes that the time given to pay is an important customer satisfaction metric and recognize an opportunity to improve in this area.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

ATTACHMENT 7

REBUTTAL TESTIMONY OF LELAND R. SNOOK

On Behalf of Arizona Public Service Company

Docket No. E-01345A-19-0236

November 6, 2020

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Attachments

REBUTTAL TESTIMONY OF LELAND R. SNOOK
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-19-0236)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Leland R. Snook. I am the Director of Rates and Rate Strategy for Arizona Public Service Company (APS or Company). I have management responsibility for all aspects relating to rate strategy and specific rates and prices. My business address is 400 North 5th Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS MATTER?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I sponsor the jurisdictional allocation of various updates to the Company's Standard Filing Requirements (SFR), an update to the Fair Value Rate Base (FVRB), Fair Value Increment (FVI), and Fair Value Rate of Return (FVROR). I also address Staff and intervenor criticisms for several recommended adjustments to APS's requested revenue requirement, APS's AG-X/AG-Y proposal, APS's Cost of Service Study (COSS), and APS's general service and school rates recommendations. I also sponsor a new adjustment mechanism called the Advanced Energy Mechanism (AEM).

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. I rebut a number of Staff and intervenor unreasonable adjustments to the revenue requirement and summarize the overall financial impact of changes APS has incorporated into its rebuttal revenue requirement. I explain why parties' AG-X/AG-Y proposals are largely unworkable because they would shift cost to other customers. I address parties' proposed modifications to APS's COSS and explain why APS's present allocation methods are sound and appropriate. I sponsor the term sheet for APS's proposed AEM, which will be critical to support the ambitious goal of providing 100% clean energy by 2050, with interim targets. Lastly, I explain why the general service rate design recommendations by the Solar Energy Industries Association (SEIA) and Arizona School Boards Association (ASBA)/Arizona Association of School Business Officials (AASBO) are flawed and should not be adopted by the Arizona Corporation Commission (ACC or Commission). While I may not address every detail related to intervenors' recommendations, it should not be interpreted that I agree with each position unless specifically stated within my testimony.

III. STANDARD FILING REQUIREMENTS

Q. ARE YOU SPONSORING ANY UPDATES TO SFR SCHEDULES?

A. Yes. I am sponsoring an update to SFR A-1, B-1, B-2, C-1 and C-2, specifically related to the Commission jurisdictional allocation.

Q. PLEASE DESCRIBE THE UPDATES TO THESE SFRS.

A. APS has made several changes to its original filing. Some surfaced through the discovery process in this case, and others were anticipated changes previously described in the Company's Direct Testimony, such as the update to post-Test Year plant (PTYP) to reflect actual plant balances through June 2020. In addition, APS is incorporating some recommendations from Staff and intervenors. These rate-base and income-statement adjustments result in changes to APS's FVRB and the FVI to rate base. In addition, as discussed by APS witnesses Barbara Lockwood and Ann Bulkley, APS has revised its requested return on equity (ROE) and the return on the FVI. The net effect of all these changes reduces the Company's requested revenue requirement by approximately $15 million.

Q. WHAT IS APS'S POSITION ON STAFF WITNESS RALPH SMITH'S ADJUSTMENT TO INCLUDE BAD DEBT IN THE CALCULATION OF THE REVENUE CONVERSION FACTOR [ATTACHMENT RCS-2, A-1]?

A. The Company accepts this adjustment. APS updated the calculation utilizing an uncollectible revenue factor of 0.41% and has provided the new information in Rebuttal SFR Schedule C-3, which is sponsored by APS witness Elizabeth Blankenship. The revised revenue conversion factor is 1.3346, which is in agreement with the revenue conversion factor reflected in Staff witness Ralph Smith's attachment RCS-2, A-1.

IV. <u>FAIR VALUE RATE OF RETURN</u>

Q. DID APS UPDATE ITS FVRB AND RATE OF RETURN FOR THE ADJUSTED TEST YEAR?

A. Yes. APS has increased its FVRB by $4.941 million. Thus, the Company's FVRB in APS's Rebuttal Testimony is now $12,315,204. The net result of all Rebuttal Testimony rate base changes, plus a downward adjustment to both the requested ROE and the FVI rate of return, produce a revised fair value rate of return of 5.51%.

Q. WHY WAS THIS UPDATE APPROPRIATE?

A. With an update for the PTYP and a number of corrections to the Company's Application, both the Original Cost Rate Base (OCRB) and Reconstructed Cost New Less Depreciation (RCND) rate based have changed. Also, APS reduced its requested ROE and FVI rate of return.

Q. DID APS USE THE SAME METHODOLOGY TO COMPUTE FVRB AND THE FVI AS IN THE APPLICATION?

A. Yes. I have revised the inputs but have used the same method of computation. Please see Attachment LRS-01RB and revised SFR Schedule A-1, line 9.

V. PRO FORMA ADJUSTMENTS

Q. ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION (AECC) WITNESS KEVIN HIGGINS ADVOCATES THE USE OF AVERAGE RATE BASE VERSUS YEAR-END VALUES FOR POST-TEST YEAR PLANT (PTYP) ADJUSTMENTS TO THE TEST-YEAR. DO YOU AGREE?

A. No. PTYP rate base and related adjustments, such as rolling forward accumulated depreciation for existing plant to the same PTYP end of period are known and measurable changes to the Test Year and should reflect year-end values of PTYP period, not average values. If there are prudent known and measurable changes to rate base in the Test Year, they should be 100% recoverable. AECC witness Higgins does not appear to contest the prudency of the expense, and therefore, his attempts to allow less than full recovery should be rejected.

Q. IS AECC'S POSITION TO ADJUST THE CUSTOMER AND SALES ANNUALIZATION PRO FROMA TO REFLECT CUSTOMER GROWTH POST-TEST YEAR APPROPRIATE?

A. No. APS included 12 months of PTYP in its application in this proceeding, but APS excluded any plant related to customer growth. Pursuant to the Settlement in the Company's last rate case, APS was given the choice of including PTYP related to growth and making an adjustment similar to what AECC is proposing or excluding growth-related plant and not imputing customer growth. AECC's imputation of post-Test Year customer and sales growth into the test period results in a double counting for the effects related to growth.

Q. AECC ALSO PROPOSES A DEBT RETURN ON APS'S REMAINING BOOK VALUE FOR NAVAJO GENERATING STATION (NGS). DO YOU AGREE WITH THIS ADJUSTMENT?

A. No. NGS served APS's customers for over 40 years, and the remaining book value of the asset is merely the final cost of a long-asset life. While depreciation rates and salvage costs are in theory supposed to result in a value close to zero at the end of plant life, in the instance where it does not, a regulatory asset or liability is created. This is not a reflection on whether the capital cost over the life of the facility was prudently incurred, it is just a mismatch in the timing. The regulatory asset for the remaining book value for NGS reflects prudently-incurred cost over the long life of the asset and therefore should receive normal regulatory asset treatment at the weighted average cost of capital (WACC) established in this proceeding. In this case, APS is still proposing recovery of the remaining book value over the original NGS life of 2026, which prevents potential rate pressure from trying to accelerate recovery to more closely match the closure date in 2019. A debt-only return is essentially a partial disallowance of prudently-incurred costs as the Company funded the related assets with a mix of debt and equity. Such a disallowance effectively punishes APS for closing or terminating its interest in the generating asset.

Q. DO YOU AGREE WITH THE FEDERAL EXECUTIVE AGENCIES' (FEA) PROPOSAL TO DISALLOW THE OCOTILLO MODERNIZATION PROJECT (OMP) DEFERRED COST?

A. No, I do not. FEA witness Michael Gorman alleges that APS has not justified including the OMP deferral in rates. The OMP accounting mechanism was set up in a Commission order supported by FEA to defer the costs of owning and operating the plant, until a determination of prudence could be made. FEA correctly concludes the OMP asset is prudent, but I disagree with his proposal to disallow the deferral.

Q. FEA ARGUES THAT APS'S REVENUES DURING THE COST DEFERRAL PERIOD WERE SUFFICIENT FOR APS TO EARN A FAIR RETURN WITHOUT THE NEED FOR SUCH A DEFERRAL. IS HE CORRECT?

A. No. Counter to FEA's claim, APS has demonstrated that its current rates were insufficient to earn its authorized ROE even with the ability to defer costs related to OMP. APS's unadjusted jurisdictional ROE in the Test Year was 9.7%, as compared to the currently authorized ROE of 10.0%. It is important to note that this actual return in the Test Year included a deferral of the OMP costs. However, had these costs been expensed, as would have been the case absent an accounting deferral order, the actual return would have been even lower. FEA's testimony ignores the fact that APS's current authorized ROE is 10.0%, and without the ability to defer OMP costs, the actual ACC jurisdictional return would have been well below the authorized return. On this point, FEA erroneously relies on FEA witness Christopher Walters' derivation of an ROE of 9.3% that is below the test year actual return of 9.7%. However, as I mentioned previously, APS's authorized ROE during the test year was 10.0%.

Q. DID THE OVERLAND REPORT OR THE DRAFT OVERLAND REPORT COME TO A SIMILAR CONCLUSION?

A. No. The final report from Overland Consulting (Overland) that was docketed in the APS Rate Review matter (Docket No. E-01345A-19-0003) concluded that a number of factors had changed since APS's 2015 Test Year rate case, and APS should file a new rate case to determine if its rates were just and reasonable. The Overland report did not conclude that APS was over-earning. Four months later, in the same docket, earlier drafts of the Overland report were docketed. These drafts discussed a hypothetical scenario that did not reflect actual circumstances.

Q. PLEASE ELABORATE. WHY DO YOU DESCRIBE THE DRAFT REPORT'S ANALYSIS AS A HYPOTHETICAL SCENARIO?

A. In one of its drafts, Overland disregarded the 10% authorized ROE set by the Commission in Decision No. 76295 and substituted a new authorized equity return of 9.0%, which was not approved by the Commission or consistent with its prior decision. Overland merely concluded that if APS's authorized return were only 9.0%, then APS's actual return might have exceeded that number. Of course, the cost of equity found by the Commission was 10.0%, not 9.0%. In discovery for the

APS Rate Review matter, APS provided Overland with actual jurisdictional results, which demonstrated APS earned less than its then-authorized cost of equity, 10.0%. The Overland draft report also used lower debt costs than those found by the ACC. Overland added to its analysis several potential pro forma adjustments to the 2018 calendar year results, but it was not a comprehensive list of proforma adjustments that would be included in an actual rate case filing. Most notably, there was no adjustment for PTYP and no fair value adjustment. In summary, Overland's draft report came to the unremarkable conclusion that if APS had spent less in the 2018 calendar year, APS would have had more net income and a higher return on equity – not that the Company was actually over-earning.

Q. DO YOU BELIEVE THAT FEA WITNESS MICHAEL GORMAN'S DEFERRAL PROPOSAL IS INAPPROPRIATE REGARDLESS OF APS'S LEVEL OF HISTORIC EARNINGS?

A. Yes. The allowed recovery of a deferral, or of any asset for that matter, should not be contingent on prior year earnings, as claimed by FEA witness Gorman. By that same reasoning, APS would be able to increase the requested recovery of a deferral in a rate case if it earned less than the currently-allowed rate of return in the years since the last rate case.

Q. DOES FEA WITNESS GORMAN HAVE AN ALTERNATIVE PROPOSAL IF THE ACC ALLOWS RECOVERY OF THE DEFERRED COSTS?

A. Yes, and it should also be rejected. FEA witness Gorman proposes to use a debt return on the amortization of the deferred costs and a levelized cost recovery over the amortization period. The use of a debt return only on the regulatory asset created by the deferred costs is contrary to normal regulatory asset treatment. APS was authorized a debt return as the carrying cost during the deferral period, but the regulatory asset should receive the same treatment as any other asset in APS's rate base.

Q. THE RESIDENTIAL UTILITY CONSUMER'S OFFICE (RUCO) PROPOSES TO ACCELERATE THE AMORTIZATION OF PRODUCTION PLANT GENERATION-RELATED ASSETS. PLEASE RESPOND.

A. RUCO witness Frank Radigan does not provide any logical support for this proposal. Essentially, such a rapid amortization would have an adverse impact on customer rates. As I indicated previously, these regulatory assets are the final settling costs for assets that reliably served APS customers for over 40 years. I disagree with the characterization of these asset costs as stranded costs – it is merely a reflection of a mismatch in the cost recovery of the asset over a long period of time. While one would ideally target the book value of a generation asset to be zero, often there is a positive or negative plant balance. This regulatory asset or liability, as the case may be, should be treated consistently. For this category of regulatory assets, APS has proposed to continue to amortize the remaining book value consistent with the asset's depreciation schedule prior to retirement. This approach does not increase or decrease the recovery of the remaining capital cost and is a balanced approach to help keep customer rates affordable.

Q. RUCO ALSO PROPOSES TO LIMIT COST RECOVERY OF APS'S EDISON ELECTRIC INSTITUTE (EEI) AND ELECTRIC POWER RESEARCH INSTITUTE (EPRI) DUES. IS THIS APPROPRIATE?

A. No, it is not. For APS's EEI dues, APS already excludes the portion of EEI dues related to legislative or regulatory advocacy. These same dues are RUCO witness Radigan's justification for reducing non-advocacy EEI dues by 50%. However, APS already removed the advocacy-related dues in its application. The remaining dues should be fully recoverable as a prudent expense to be a member of this valuable electric industry trade organization. Further, EPRI is an industry research organization that is important for APS to participate in to stay abreast of the evolving electric utility industry. These necessary expenses should be fully recoverable as prudently-incurred costs. Particularly in today's rapidly-changing electric industry, it is not a viable option for APS to drop its membership in EPRI.

Q. ARE YOU SPONSORING ANY NEW OR UPDATED PRO FORMAS IN REBUTTAL?

A. Yes. Through the discovery process, the Company realized it had inadvertently omitted a revenue pro forma to account for the AG-X program mitigation that occurs through the Power Supply Adjustor (PSA) mechanism, which amounts to $15 million in revenue annually, that should have been a reduction in the revenue deficiency APS is requesting in this rate case. Thus, the revised Standard Filing Requirement (SFR) C-2, attached to APS witness Elizabeth Blankenship's Rebuttal Testimony, incorporates this new pro forma. This pro forma can be seen on SFR C-2, page 18, column 52.

Q. WHAT IS THIS PRO FORMA, AND WHY IS IT NECESSARY?

A. As part of the AG-X program, APS retains $1.25 million in margins from wholesale sales per month from the margins that credit the overall APS fuel costs in the PSA. This pro forma corrects APS's original application filing to reflect that these revenues are retained through the PSA mechanism, and the $15 million annual amount should not be reflected in the revenue deficiency. Therefore, the $15 million is now correctly reflected in both the ongoing PSA Plan of Administration and in the retail jurisdictional revenue requirement.

Q. ARE THERE ANY OTHER NEW/UPDATED PRO FORMAS?

A. Yes. APS adopts Staff's recommendation to increase the base fuel rate from $3.0167 to $3.1451. This recommendation was based on an updated fuel forecast provided by APS in discovery. APS believes its original estimate of base fuel costs was reasonable but will not contest Staff's position. This pro forma can be seen on SFR C-2, page 2, column 6.

Q. WOULD YOU PLEASE SUMMARIZE THESE PROPOSED CHANGES TO ADJUSTED TEST YEAR OPERATING INCOME, RATE BASE AND RATE OF RETURN?

A. Please see Table 1 below for major components of the changes (numbers have been rounded for ease of presentation). The income statement and rate base pro formas are discussed by either APS witness Blankenship or myself. The changes to requested ROE and return on FVI are discussed by APS witness Barbara Lockwood. The annual revenue requested in rebuttal is $169 million, which equates to a 5.14% average bill impact.

Table 1. APS Revised Revenue Requirement

APS Revised Revenue Requirement	Dollars ($MM)	Bill Impact
Total Revenue Deficiency in APS's Application	184	5.60%
Rebuttal Base Rate Impact		
Income Statement and Rate Base Pro Forma Changes		
New base fuel rate	25	0.77%
Depreciation Update	(20)	-0.61%
Normalize Employee Benefits Update	(10)	-0.29%
AG-X Revenue Provision in PSA Update	(11)	-0.34%
Other C-2 Pro Forma Updates	(10)	-0.31%
Misc. Adjustments	(3)	-0.09%
B-2 Pro Forma Updates	2	0.07%
Changes to Requested Returns		
Decrease in ROE	(9)	-0.29%
Decrease in Return on FVI & RCND Update	(10)	-0.29%
Other		
Transmission Expense Correction	18	0.53%
Adjustor Impact		
TEAM Adjustor	(119)	-3.62%
Other Adjustor Mechanisms	4	0.12%
Revised Net Base Rate Increase	**41**	**1.23%**
Rebuttal Adjustor Impact		
Removal of TEAM credit	119	3.62%
Advanced Energy Mechanism (AEM)	13	0.41%
Other Adjustor Mechanisms	(4)	-0.12%
Net Adjustor Changes	**128**	**3.91%**
Total Rebuttal Customer Bill Impact	**169**	**5.14%**

To accurately reflect the bill impact of the Company's revised rate request, which is an average of 5.14% for all customers and 4.99% for residential customers, I have included the impact of adjustor changes such as the proposed recovery of the Coal Community Transition (CCT) commitment described by APS witnesses Jeff Guldner and Barbara Lockwood. This is a total of $13 million recovered through the AEM. I discuss the details of this mechanism elsewhere in my Rebuttal Testimony.

Q. ARE THERE ANY ITEMS IN THE TABLE THAT HAVE NOT BEEN DISCUSSED IN APS REBUTTAL TESTIMONY?

A. Yes. I have included a line item under "Other Impacts" that were identified in the discovery process. Transmission expense for March 2019 was inadvertently omitted from the model, resulting in an understatement of revenue requirement by $18 million.

VI. FORMULA RATE, THE AEM MECHANISM AND OTHER ADJUSTOR MECHANISMS

A. *Existing Adjustors*

Q. DID INTERVENORS WEIGH IN ON APS'S CURRENT ADJUSTOR MECHANISMS OR APS'S FORMULA RATE PROPOSAL?

A. Yes. I note that Staff witness Ralph Smith agrees with APS's proposal to not transfer the balance in the Lost Fixed Cost Recovery (LFCR) adjustor into base rates. Additionally, several parties provided commentary on APS's alternative formula rate proposal.

Q. SOUTHWEST ENERGY EFFICIENCY PROJECT (SWEEP)/WESTERN RESOURCE ADVOCATES (WRA) SUGGESTS THAT APS'S LFCR MECHANISM SHOULD BOTH BE ZEROED OUT IN THIS CASE AND PROSPECTIVELY HAVE AN EARNINGS TEST. ARE EITHER OF THESE RECOMMENDATIONS APPROPRIATE?

A. No. APS has no theoretical objection to transferring all unrecovered fixed costs recoverable under the LFCR to base rates, essentially zeroing out the LFCR as of the rate effective date. However, the mechanics of this are complicated, and as the last case demonstrated, the bill impact is difficult to explain to customers. Thus, neither APS nor Staff recommend this course of action at this time.

As to the earnings test, LFCR is recovery of lost fixed costs irrespective of a utility's earnings. LFCR is based on actual observed reduced sales that result from Energy

Efficiency (EE) and Distributed Generation (DG) programs – not a hypothetical change in sales. The LFCR is intended to eliminate the disincentive of the utility to engage in EE and support DG programs. Putting an earnings test on the LFCR would undermine the intent of this mechanism.

Q. INTEVENOR RICHARD GAYER ALLEGES THE ADJUSTOR TRANSFER ACTUALLY NEVER OCCURRED IN APS'S PREVIOUS RATE CASE. PLEASE RESPOND.

A. Intervenor Gayer is mistaken, and his allegation was conclusively addressed in Docket No. E-01345A-18-0002. Decision No. 77292 in the aforementioned docket specifically found as a finding of fact and conclusion of law that the adjustor transfer occurred in accordance with the normal functioning of the various adjustor mechanisms.

Q. IS THE COMPANY PROPOSING ANY OTHER CHANGES TO ADJUSTOR MECHANISMS OTHER THAN WHAT WAS PROPOSED IN ITS DIRECT TESTIMONY?

A. Yes. APS now believes it is more appropriate to retain the current Tax Expense Adjustor Mechanism (TEAM) rather than eliminate it. APS proposes to set the adjustor value to zero but retain the mechanism in anticipation of future changes to federal or state income tax policy. Keeping this adjustor would allow APS to properly reflect changes in tax expense moving forward. Without it, depending on timing, the Company could be forced to file an immediate rate case to address tax changes in the future.

B. *Formula Rates and the AEM*

Q. DOES ANY PARTY SUPPORT APS'S FORMULA RATE PROPOSAL?

A. No. Parties oppose this concept at this time for a variety of reasons. Because this proposal was: 1) an alternative proposal for consideration; 2) parties did not propose to eliminate the current suite of adjustor mechanisms; and 3) the concept did not generate support, APS is no longer pursuing this proposal as part of its rebuttal case. As such, I will not respond in detail to parties who provided testimony opposing the formula rate proposal.

While parties did not support comprehensively moving to using a formula rate mechanism to more closely match revenue recovery with expenses, there exists an opportunity to continue to align interests from a number of parties, while providing timely cost recovery for APS in its efforts to support a clean energy future for Arizona. To that end, APS is proposing a new adjustor described in the rebuttal testimonies of APS witnesses Guldner and Lockwood – an adjustor the Company calls the AEM.

Q. DID APS ANNOUNCE A CLEAN ENERGY PLAN IN JANUARY OF 2020 AFTER THIS RATE CASE APPLCATION WAS FILED?

A. Yes. As discussed in more detail by APS witnesses Guldner and Lockwood, APS committed to be 100% clean (carbon free) by 2050, with interim targets as well. The Clean Energy Commitment is an ambitious undertaking, and to be successful, APS will need timely cost recovery of its investments to meet the commitment.

Q. HOW IS APS PROPSING IT RECOVER THESE COSTS?

A. APS is proposing to recover investments related to the Clean Energy Commitment through the AEM. In addition, because they all encourage a cleaner energy future, the AEM could be modified to include the existing Demand Side Management (DSM), renewable energy, and LFCR mechanisms after a period of time. In APS's proposal, the CCT funding discussed by APS witnesses Guldner and Lockwood would be recovered through this adjustor. APS witnesses Guldner and Lockwood also both discuss the importance of timely recovery in pursuing clean energy goals, and I have included an AEM term sheet as Attachment LRS-02RB.

Q. WHAT COSTS WOULD BE RECOVERABLE IN THIS PROPOSED AEM?

A. This mechanism would provide for timely cost recovery of the capital carrying cost and expense of APS's approved and prudent clean plan investment, including APS-owned, newly-constructed or acquired plants which are not already recovered in base rates or through another Commission-approved cost adjustment. For example, purchased power costs and third-party storage costs are already includable in the PSA mechanism, and a portion of renewable costs are recovered in base rates.

Q. HOW WOULD CLEAN ENERGY INVESTMENTS BE DETERMINED?

A. Clean energy investments would be authorized by the Integrated Resource Plan (IRP) Action Plan or Clean Energy Implementation Plan approval by the ACC and a subject to a robust request for proposal (RFP) process. Approved and prudent acquisitions that result from the IRP Action Plan or Clean Energy Implementation Plan and RFP process would be included in the AEM for cost recovery.

Q. IF THE COMMISSION DOES NOT APPROVE THIS ADVANCED ENERGY MECHANISM, ARE THERE OTHER ALTERNATIVES USING EXISTING MECHANISMS?

A. Yes, there is. APS could use the existing Renewable Energy Adjustment Charge (REAC), DSMAC, and LFCR for clean energy plan cost recovery. The REAC would recover the capital carrying cost of APS-owned resources, including storage-related facilities. In this scenario, the CCT funding could be added to base rates.

VII. ENERGY EFFICIENCY PROPOSAL

Q. VARIOUS INTERVENORS PROPOSE CHANGES TO THE AMOUNT OF DSM PROGRAM COSTS TO BE INCLUDED IN BASE RATES. DOES APS SUPPORT THESE PROPOSED CHANGES?

A. Not at this time. AECC proposes that no DSM program costs be recovered through base rates, and SWEEP/WRA witness Brendon Baatz proposes that the amount of DSM in base rates be increased from $20 million to $65 million. APS is open to increasing the amount of DSM program costs being recovered in base rates but proposes that any addition be revenue neutral, meaning the increased amount would not exceed the Test Year amount in the DSM adjustor.

Q. WHAT IS THE PROPOSAL OUTLINED BY SWEEP/WRA FOR CAPITALIZATION OF DSM COSTS?

A. SWEEP/WRA recommend that APS be allowed to earn a rate of return on EE investment. This would be effectuated by creating a regulatory asset for the annual expenditure and amortizing that over a 7-year period, with a return at the after-tax cost of capital on the unamortized balance of this asset.

Q. WHAT ARE SOME PROS AND CONS OF CAPITALIZING DSM EXPENSES?

A. By amortizing DSM costs over a period of time, capitalization better aligns the costs of the resource with the timing of benefits. It protects customers by ensuring DSM costs are appropriately apportioned across a period of time closer to the 10-year average measure life of the DSM portfolio, rather than asking current customers to fully fund all DSM costs upfront. It also helps put DSM investments on a more level playing field with other investments and can encourage investments in appropriate demand-side resources. Implementing capitalization at this time could be particularly valuable as a tool to help mitigate the economic impacts of COVID-19 by providing short-term rate relief, while still enabling robust investments in EE and other DSM resources.

On the other hand, the impacts on total costs must also be considered. Capitalizing costs will increase the total cost of demand-side resources and could potentially limit future program spending on new programs due to the carrying costs of amortized investments over time. This potential impact on costs must be further analyzed and addressed, as well as creating provisions for a transition period to define how amortized costs would be recovered if the Commission were to revert to an operating expense approach at some point in the future. Finally, any capitalization plan must address the unique risks associated with deferring DSM costs which would be considered as a regulatory asset with no value outside of the regulatory construct – requiring a clear framework to be established to provide reasonable assurance of future cost recovery.

Q. WHAT IS APS'S POSITION ON SWEEP/WRA'S PROPOSAL TO CAPITALIZE DSM EXPENSES?

A. APS is interested in the proposal. As the EE focus in Arizona has shifted to peak management, I believe that this type of proposal aligns with the general proposition that EE should be treated like supply-side resources.

Q. IS APS RECOMMENDING ADOPTION OF THE SWEEP/WRA PROPOSAL AT THIS TIME?

A. APS is interested in this proposal, but is still analyzing the impacts, as stated above. APS welcomes feedback from other parties on this topic.

VIII. <u>COMMERCIAL BUY-THROUGH PROGRAMS (AG-X/AG-Y)</u>

Q. SEVERAL INTERVENORS ASSERT THAT APS'S PROPOSED PROGRAM IS INCONSISTENT WITH THE ACC'S POLICY STATEMENT REGARDING AG-Y. DO YOU AGREE?

A. Not at all. The policy statement clearly states that the program shall not shift costs to non-participating customers.[1] This is a point conveniently left out by intervenors. In fact, while AECC erroneously claims that the PSA mitigation is no longer needed, without it there would be a revenue shortfall that would need to be made up through higher rates to other customers to offset the cost shift created by AG-X. AECC suggests a similar mitigation mechanism would be needed for their AG-Y proposal

[1] Decision No. 77043, AG-Y Policy Statement at 3.

that essentially mirrors AG-X. Importantly, Staff supports the program because it does not shift costs to other customers.

Q. IS THERE ANYTHING ELSE YOU WOULD LIKE TO POINT OUT ABOUT THE POLICY STATEMENT?

A. Yes, the policy statement cites that a benefit of this program should be that it "provides medium and large commercial customers increased flexibility to manage their energy costs while insulating other customers from cost shifting."[2] This is precisely what APS's proposal does.

Q. DID VARIOUS INTERVENORS MAKE SUGGESTIONS REGARDING THE AG-Y PROPOSAL?

A. Yes. AECC, Calpine Energy Solutions (Calpine), Walmart Inc., The Kroger Company, Staff and FEA all provide testimony regarding APS's proposed AG-Y program. Staff did not oppose the proposed program. Generally, the market brokers and large customer constituents proposed to expand the current AG-X program rather than offer a new AG-Y program. FEA alternatively proposes some modifications to the eligibility for APS's proposed AG-Y program if the AG-X program is not expanded.

Q. DOES THE COMPANY AGREE WITH THE RECOMMENDATIONS TO EXPAND AG-X?

A. No. The current AG-X program cannot be expanded, either by allowing for growth in the current program or by changing the proposed AG-Y program into an AG-X concept, without requiring additional mitigation through the PSA, increased AG-X/AG-Y charges, and removing the buy-through priority to deliver power at the Palo Verde market hub. Most importantly, resource adequacy deficiencies in the current program would have to be addressed. Despite the issues discussed below, APS has

[2] Decision No. 77043, AG-Y Policy Statement at 1.

not proposed changes to the AG-X program in this case. Therefore, APS continues to support its AG-Y proposal in this case because it provides customers with a market price for their energy, if the customer so desires, without creating the potential to shift costs to other customers as can occur in the current AG-X program.

Q. PLEASE DESCRIBE HOW THE CURRENT AG-X PROGRAM WORKS.

A. The current AG-X program allows customers to receive their power supply from a third-party generation service provider (GSP) rather than from APS. APS continues to provide transmission and distribution grid services according to the customer's retail rate schedule. The customer avoids the unbundled generation capacity and energy charges in the retail rate, including the PSA Adjustor charge, but pays a reserve capacity charge and an administrative fee. They also pay for the generation charges from the GSP.

Q. PLEASE ELABORATE ON THE COST DEFICIENCIES IN THE CURRENT AG-X PROGRAM.

A. The primary deficiency in the current AG-X program is that the GSPs do not provide all of the generation services needed to serve the customer – they do not act as an alternative to, or substitute for, APS. They do not serve the customer with power plants that can ramp up and down to match the customer's monthly, daily, or hourly loads and provide a firm resource to ensure a reliable power supply for the customer. Rather, they typically serve the customer through block energy purchases from wholesale brokers or suppliers like the California Independent System Operator (CAISO), which can be interrupted during critical load hours. They leave it to APS to provide the capacity resources and reserves needed to reliably serve the customer's load.

Q. CALPINE WITNESS GREG BASS CLAIMS THAT THEY ARE PROVIDING FIRM POWER. DO YOU AGREE?

A. No. And by firm power, I mean providing both energy and capacity to reliably serve a customer from a power supply that provides resource adequacy for the load being served. Calpine witness Bass generally confuses capacity and energy in making his firm-power claim. The AG-X program requires that GSPs deliver power in a particular standard energy contract form called WSPP Schedule C, which is a firm energy contract. Calpine claims that this type of contract provides firm capacity, as well as energy. However, this is incorrect. The WSPP Schedule C is essentially an energy contract, which can be cut during critical hours and does not provide any of the power plant capacity attributes or resource adequacy requirements for ensuring a reliable supply of power to the customer.

Q. WERE THESE DEFICIENCIES HIGHLIGHTED IN THE RECENT POWER SHORTAGES IN THE SOUTHWEST?

A. Very much so. APS witness Brad Albert will elaborate on the Summer 2020 wholesale power market and events that occurred in the western states during a regional heat storm, but essentially AG-X participants had their schedules cut during peak hours, causing APS to use its own resources to serve AG-X customers' load.

Q. BUT CAN'T APS SIMPLY CURTAIL THE AG-X CUSTOMERS' LOAD IF THEIR POWER SUPPLY IS CUT DURING CRITICAL HOURS?

A. No, not under the current program. Furthermore, as the balancing authority, APS has an obligation to serve each of the customer loads in its area, even the AG-X loads that should be served by the GSPs. AG-X customers include hospitals, universities, grocery stores and retail stores, which expect to have reliable power, even if they participate in the AG-X program.

Q. CALPINE ALSO CLAIMS THE ONE-YEAR RETURN WARNING ALLEVIATES THE CAPACITY ISSUE. IS THIS CORRECT?

A. No. AG-X customers must provide a one-year warning before they can return to APS's generation service, under the retail rate schedule. Or, if the GSP defaults, they could be served at market index rates for up to one year. Calpine contends that this means that APS does not have to plan for any future power plant capacity for the AG-X customers. However, because the customer cannot be curtailed if the GSP fails to provide generation during critical times, this requirement does little to nothing to alleviate the need for APS to back up the GSP's supply.

Q. DO THE GSPS PAY FOR THE DEFICIENT CAPACITY THAT IS MADE UP BY APS DURING CRITICAL HOURS?

A. Only partially. The GSPs pay liquidated damages when their power supply is cut, which is based on the cost of replacement energy for the deficient hours. However, this replacement energy, which can be relatively high during critical hours, is only applied to the actual hours of deficiency and, therefore, is far less than the cost of an actual power plant or a capacity contract necessary for providing resource adequacy to customers.

Q. DO THE GSPS PAY FOR THE TYPE OF GENERATION NEEDED TO FOLLOW THEIR LOAD EACH SECOND?

A. Again, only partially. AG-X customers, like all retail customers, pay for a "regulation and frequency response" service in their retail transmission charge. This service recovers the cost of a very small amount of generation that can instantaneously ramp up and down, under automatic controls, to match supply with load at every instant. It covers small deviations in load each second that were not perfectly anticipated nor provided for with the scheduled power supply. However, if APS and other load-serving entities only provided blocks of power to serve their customers, similar to the GSP supply in the AG-X program, the cost for this service would undoubtedly be significantly higher. In fact, under this scenario, there could very likely not be enough resources to provide this service.

Q. DO THE AG-X CUSTOMERS PAY FOR THE OTHER CAPACITY SERVICES DISCUSSED?

A. Only partially. The AG-X customers pay a reserve capacity charge and transmission ancillary charges, but these charges only partially address the costs for these unprovided generation services. The remaining costs are mitigated through the retained PSA margins or are shifted to other customers.

Q. AECC CLAIMS THAT THE RESERVE CAPACITY CHARGE SHOULD BE SIGNIFICANTLY REDUCED. DO YOU AGREE?

A. No. AECC witness Kevin Higgins' proposal is based on an incorrect conception of the purpose for this charge. AECC mistakenly believes that the capacity reserve charge is some sort of payment for APS legacy power plants that are no longer needed to serve the AG-X customers. Therefore, AECC argues that the charge should be reduced because AG-X customers have been paying off these legacy power plant costs for some seven years.

This line of reasoning is simply incorrect. The reserve capacity charge partially recovers the costs of APS power plants that are still needed to serve the AG-X customers because of the deficiencies of the GSP power supply under the program discussed above. This is an ongoing annual cost that is not "paid down" in any manner. Therefore, the reserve capacity charge should not be reduced. As a matter of fact, the charge only partially recovers the costs of APS power plant capacity provided under the program.

Q. WHAT CHARGES SHOULD THE AG-X CUSTOMERS PAY?

A. Because APS continues to provide the generation capacity services for the AG-X customers, ideally, they should continue to pay the full unbundled generation capacity charge in their retail rate. They should continue to avoid paying the generation energy charge and the PSA Adjustor charge. However, in its current form, APS is not proposing these changes.

Q. ISN'T THAT PRECISELY THE CONCEPT OF THE PROPOSED AG-Y PROGRAM?

A. Yes, it is. Under the proposed AG-Y program, the customer would continue to pay the unbundled generation capacity charge in their retail rate – to pay for the capacity services provided by APS – and substitute the unbundled generation energy charges and PSA charges for a market rate. It would operate like a market generation rate should – providing bill savings consistent with the generation costs savings incurred under the program.

Q. THEN WHY DO CERTAIN GSPS AND CUSTOMER GROUPS OPPOSE THE AG-Y PROGRAM?

A. Under the AG-X program, the potential for customers to save money or GSPs to make money are greater. The generation capacity services that APS continues to provide under the AG-X program are effectively paid for by PSA mitigation or other customers, not the participants. This results in significantly higher benefits for the AG-X participants and GSPs, compared to the proposed AG-Y program, where the customer benefits are more consistent with the actual generation cost savings.

Q. WHAT DOES APS PROPOSE ON THIS ISSUE?

A. Consistent with the filed case, APS proposes to allow the current AG-X program to continue without revision and to provide the AG-Y program for additional customers that want to access market generation prices. If the Commission were to expand the AG-X program as suggested by GSPs and large-customer intervenors, it could not be done under the current construct without shifting costs significantly to non-participants.

Q. DID PARTIES PROPOSE OTHER CHANGES TO THE CURRENT AG-X PROGRAM THAT APS OPPOSES?

A. Yes. AECC witness Higgins proposes that the AG-X program allow for load growth. While APS supports accommodating reasonable load growth, this should not become a mechanism to dramatically increase the overall size of the program. One example would be if an extra-large customer in the program desired to double their existing load through an expansion. This would violate the intent of the overall program size limitation, which is important. Some reasonable amount of growth can be accommodated but should be limited. A 10 MW customer should not be able to add 10 MW, and an 80 MW customer should not be able to add 80 MW. A reasonable accommodation would be to limit growth to 10% of the original program allotment.

Q. DID PARTIES PROPOSE ANY CHANGES TO THE AG-X PROGRAM THAT THE COMPANY SUPPORTS?

A. Yes. There are two minor modifications that APS supports. First, Kroger witness Stephen Baron proposes the AG-X program allow for customers that aggregate accounts to be able to add accounts if the aggregate load falls below the 10 MW threshold due their participation in EE programs. APS agrees this would be a reasonable accommodation within the AG-X program, to allow locations to be added to get back to the original allocated program amount. Second, AECC suggests that APS change the scheduling procedure to allow for intra-day scheduling changes by the GSP. APS agrees this is a reasonable change to the current scheduling protocols. Such intra-day trading capabilities would have to be developed and integrated into APS's current scheduling platform and protocols. However, APS is committed to working with GSPs and customers to develop additional scheduling capabilities for the AG-X program.

Q. DO ANY OTHER PARTIES PRESENT TESTIMONY ON THE AG-Y PROPOSAL?

A. Yes, ASBA/AASBO discuss the program as well.

Q. DOES APS SUPPORT ASBA/AASBO'S RECOMMENDATION?

A. Schools are already eligible under APS's proposed AG-Y program, and there is no aggregation requirement. Therefore, (as discussed later in my testimony) APS does not support the aggregation recommendation.

While APS does not support a carve-out specifically for schools at this time, the AG-Y program is specifically designed for smaller customers, such as schools. APS agrees that the load characteristics of schools could be an ideal fit to maximize the benefit of the day-ahead pricing structure. I note that, once the proposed program has time to function, APS may lift the cap of 200 MW which would allow additional opportunities for participation.

Q. SOME PARTIES ADDRESS THE QUESTION OF RETAIL COMPETITION IN THIS DOCKET. PLEASE COMMENT.

A. APS agrees with Staff witness Phillip Metzger on this issue. Retail competition is a broader policy issue that can only be addressed in a retail competition docket. The Commission has a retail competition docket open for that discussion and potential rulemaking.[3] The issue is not appropriate to address in a utility-specific rate case.

IX. <u>COST OF SERVICE STUDY (COSS)</u>

A. *General Background*

Q. WHAT IS A COST OF SERVICE STUDY?

A. A cost of service study allocates the Test Year rate base and revenue requirements across various customer and rate classes based on a reasonable estimate of the cost responsibility for each class. The study compares the adjusted Test Year revenue

[3] Docket No. RE-00000A-18-0405.

with the allocated revenue requirement to determine a revenue deficiency for each class.

Q. HOW DOES APS CONDUCT THE COSS?

A. Costs are first separated into functional categories, such as production (generation), transmission and distribution. Within each of these functional categories, the costs are further classified into (sorted by) general cost drivers such as demand, energy and customer-related costs. Notably, customer-related costs are not driven by the amount of demand or energy used by the customer. After the cost components are sorted into a more manageable and logical form, specific cost allocators are developed within these broad categories. These allocators are then applied to the cost-driver information and rate class for each customer to determine cost responsibility for each class.

B. *Criticisms of the Company's COSS Other Than by Solar Advocates*

Q. DID YOU REVIEW THE TESTIMONY OF OTHER PARTIES CONCERNING THE COSS?

A. Yes, I did.

Q. WHAT IS YOUR GENERAL RESPONSE TO THESE CRITICISMS FROM THESE PARTIES?

A. First, cost-allocation methods are not black and white. Often, there is more than one valid way to allocate certain costs, and there are varying conceptual ideas on cost-of-service methods. However, APS uses cost-allocation methods that are conceptually valid, widely adopted by the industry, and accepted historically by the Commission. It is also important to be consistent in the allocation methods used in a COSS over time because it supports consistency in rate design and customer impacts. Therefore, from my perspective, there must be a compelling reason for changing the current COSS methods APS used in this and prior rate cases.

Q. WHAT CRITIQUES TO THE COSS DID STAFF PROVIDE?

A. Staff witness David Dismukes makes several recommendations to cost-allocation methods within the COSS. Most notably, he proposes APS use an Average and Peak, and four coincident peak months (June through September), designated as (A&P–4CP) rather than Average and Excess (A&E), for allocating capacity-related production costs. Additionally, he takes issue with APS's allocation of secondary distribution costs, which uses a Sum of Individual Max (SIM) allocator, and instead proposes APS use a 100% class non-coincident peak (NCP) allocator.

APS disagrees with Staff witness Dismukes' recommendations, which to my knowledge have never been previously raised by Staff. I also note that AECC, FEA and Kroger all support APS's production cost-allocation method. I will discuss APS's opposition to these two changes to the COSS in more detail below.

Q. PLEASE DESCRIBE THE A&E METHOD.

A. APS uses the A&E method for allocating production demand costs, which uses a combination of peak demand and annual energy information to estimate the cost responsibility for each class. This method separates demand into two components: average demand and excess demand. The combination of both components is used to determine the share of production demand costs that are allocated to each class. Average demand is derived by calculating the average hourly demand for each hour of the year for each class. This conceptually reflects a base level of demand that drives the costs for baseload power plants. Excess demand is determined by the amount of Non-Coincident-Peak (NCP) demand that is above (in excess of) the average demand for each class. This component conceptually reflects the cost driver for peaking power plants. This method is conceptually valid and widely accepted in the industry. Intervenors Kroger, AECC and FEA support this allocation method, while Staff proposes an alternate method.

Q. WHY DOES STAFF WITNESS DISMUKES PROPOSE AN ALTERNATIVE METHOD?

A. Staff witness Dismukes claims that the A&E method is erroneous because it uses NCP information rather than coincident-peak (CP) information to allocate the excess demand costs.[4] Staff witness Dismukes proposes an alternative method called the average-and-peak allocator.

Q. DOES STAFF WITNESS DISMUKES IDENTIFY ANY COMPELLING REASON TO CHANGE PRODUCTION DEMAND ALLOCATION METHODS?

A. No. It has been commonly understood for decades that, under the A&E method, the class NCP must be used to allocate the excess component because if class CP information is used, the allocator mathematically reduces into a pure one CP allocator, which would not meet the ACC's desire for a production demand allocator that includes both demand and energy information. The A&E method is widely accepted as an appropriate method for allocating production demand costs, particularly when there is a desire for an allocation based on both demand and energy characteristics. Notably, the proposal to change methodologies does not even lead to a significant change in the results of the COSS.

Q. WHAT DO YOU RECOMMEND CONCERNING STAFF'S PROPOSAL FOR A NEW PRODUCTION DEMAND ALLOCATOR?

A. APS recommends the Commission continue to use the A&E method for allocating production demand costs in APS's COSS for the following reasons:

- The current A&E method is conceptually valid;

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[4] Staff Direct Testimony of David Dismukes at 16-18.

- It is widely accepted in the industry and is supported by other intervenors in this proceeding;
- It has been widely approved by the ACC without objection in the last three APS rate cases, and it is currently used by TEP/UNSE;
- Staff has not provided any reason for making this change at this time; and
- The difference in the results of the two methods is not significant.

Q. DID PARTIES RAISE ANY OTHER ISSUES CONCERNING THE ALLOCATION OF PRODUCTION DEMAND COSTS UNRELATED TO THE USE OF A&E?

A. Yes. FEA witness Amanda Alderson raised a concern that some production demand costs are embedded in certain Purchased Power Agreement(s) (PPA(s)), which are allocated as energy costs in the COSS. FEA witness Alderson proposes that a portion of the PPA cost be reclassified as production demand-related cost rather than energy-related cost. As production demand costs, she suggests they be allocated using the A&E method, rather than with an energy allocator.

Q. WHAT ARE YOUR THOUGHTS ON ALLOCATING PPA CAPACITY COSTS USING THE A&E METHOD IN APS'S COSS?

A. I believe FEA witness Alderson raises a valid, if perhaps largely theoretical, concern. I say theoretical because there are little or no capacity costs inherent in current purchased power costs. However, as I discuss below, the Commission should direct APS to evaluate this in the COSS in its next rate case, rather than specifically incorporating this change into this rate case, primarily because APS is recommending a proportional allocation of the requested increase irrespective of the COSS results.

Q. PLEASE DESCRIBE THE DISTRIBUTION COST ISSUES RAISED BY OTHER PARTIES.

A. FEA believes that a portion of distribution costs should be considered to be customer-related versus demand-related costs, while Staff contends that secondary distribution costs should be allocated in a different manner. SWEEP/WRA argues that APS has included distribution costs in the customer cost category that are inappropriate.

Q. WHAT ARE DISTRIBUTION COSTS?

A. Distribution costs comprise a wide array of cost components associated with the construction, maintenance, and operation of the local power grid. This includes substations, the primary lines that deliver power from the substations to the customer transformer, and the secondary equipment, which includes the customer transformer and the service drop to the home. It excludes the transmission grid, which is the extra-high voltage lines and equipment that deliver power from power plants to the local distribution grid. It also excludes the meter and certain point-of-delivery equipment that are included in revenue cycle service costs, such as metering, meter reading, billing, etc.

Q. WHAT IS FEA'S ISSUE CONCERNING DISTRIBUTION COSTS?

A. As I stated above, to make the COSS more transparent, costs are sorted or classified into broad categories that reflect general cost drivers, such as demand, energy and customer. FEA claims that a significant portion of the primary and secondary distribution costs, including, among other things, distribution lines and poles, should be reclassified as customer-related versus the demand-related classification used in APS's COSS.

Q. WHY DOES FEA MAKE THIS CLAIM?

A. FEA contends that a certain level of distribution equipment is needed to "hook-up" the customer to the grid, regardless of how much power they consume.[5] Therefore, this portion of distribution costs should be reclassified as customer-related costs.

Q. DO YOU AGREE?

A. Conceptually, yes. While I do not necessarily agree with all the details of FEA's claim and proposed solution, I do agree that a portion of distribution costs could reasonably be classified as customer-related costs. In fact, I believe it may go beyond the minimal system concept discussed by FEA.

Q. PLEASE EXPLAIN.

A. Certain distribution costs do not vary with the customer's monthly peak demand or their monthly energy usage. They may be sized to accommodate a maximum demand from the customer, but once installed, they do not vary with the customer's monthly load. Furthermore, some of these costs are dedicated to either individual customers or a small group of customers. Therefore, any excess capacity from one customer, or small customer group, cannot be shared with or used to serve another customer. The customer line transformer and secondary service drop to the home are examples of these types of fixed customer distribution costs. These types of fixed distribution costs are appropriate to include in customer-related costs.

In addition, common overhead costs necessary to operate the grid, such as communication and control equipment or cybersecurity costs, are unrelated to a customer's monthly demand or energy. These types of common costs could also appropriately be considered customer-related costs.

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[5] FEA Direct Testimony of Amanda Alderson at 15.

Q. HAS APS MADE THESE ARGUMENTS IN A PRIOR RATE CASE?

A. Yes. APS discussed the customer cost issue in its last general rate case.[6] The discussion supported APS's proposal to increase basic service charges for residential and commercial customers.

Q. DID APS RECLASSIFY THESE DISTRIBUTION COSTS IN THE COSS IN THIS RATE CASE?

A. No. The main reasons to perform such a reclassification study are to support proposed increases to the monthly basic service charges or support significant differences in the proposed rate increase for various customer classes. APS is not proposing a cost of service based increase to basic service charges in this case, beyond the across-the-board increases to all charges. In addition, APS is proposing a proportional allocation of bill impacts to all customer classes in this case. Therefore, APS did not conduct a distribution reclassification study in this case.

Q. DOES APS AGREE WITH ALL OF FEA'S PROPOSALS ON THIS ISSUE?

A. No. FEA proposes that APS perform one of two specific studies in its next rate case and recompute the COSS in this case using a prescribed percentage cost reclassification. While I generally agree with FEA witness Alderson's concern, I do not propose to make a change to the COSS in this case for the reasons stated above. Furthermore, FEA's proposal for APS's next rate case limits the investigation to two specific methods. As discussed above, APS's thinking on this matter goes beyond the historical concepts embodied in FEA's analysis and proposal.

Q. WHAT DOES APS PROPOSE ON THIS ISSUE?

A. APS proposes the Commission direct APS to evaluate this issue in the COSS in APS's next rate case but not incorporate this proposed change in this case.

[6] APS 2016 General Rate Case Direct Testimony of Charles Miessner at 31-32.

Q. DOES SWEEP/WRA WITNESS BAATZ ESSENTIALLY PROPOSE THE OPPOSITE ALLOCATION TREATMENT OF THESE COSTS AS PROPOSED BY FEA?

A. Yes. SWEEP/WRA witness Baatz argues a narrow definition of customer costs to justify lower customer charges. This is incorrect and will be addressed in more detail by APS witness Jessica Hobbick.

Q. WHAT IS STAFF WITNESS DISMUKES' ISSUE CONCERNING DISTRIBUTION COSTS?

A. Staff witness Dismukes contends that secondary distribution costs should be allocated with a different method than what APS used in its COSS.

Q. WHAT ARE SECONDARY DISTRIBUTION COSTS?

A. As discussed above, secondary distribution costs include the customer line transformer, which is the pad-mounted or pole-mounted transformer by a customer's home, the service drop to the home, and certain other point-of-delivery equipment.

Q. WHAT ARE THE COST DRIVERS FOR THESE COSTS?

A. Secondary distribution costs are typically driven by the kW power demands of individual homes or small groups of homes. The equipment is sized specifically for the location being served and cannot be used to serve the power needs in another neighborhood. As discussed above, some of these costs could be considered "fixed" costs and therefore could be classified as customer-related costs.

Q. HOW ARE THESE COSTS ALLOCATED BY APS IN THE COSS?

A. The secondary distribution costs are allocated by the SIM allocator, which uses the individual maximum demands of the homes or businesses for each customer class. This is consistent with the cost driver. This allocator adds together the individual peak demands for each customer each month. These individual demands will occur at different hours and days in a month, depending on the load pattern for each home.

Q. WHAT DOES STAFF WITNESS DISMUKES PROPOSE FOR THIS ALLOCATION FACTOR?

A. Staff witness Dismukes proposes to allocate these costs based on the NCP information, which is the composite demand for all customers in a class, on the same day and hour of the month. He suggests this is appropriate based on the purported observation that there is considerable load diversity among APS's customers.[7]

Q. DO YOU AGREE WITH MR. DISMUKES' PROPOSAL?

A. No. This proposal is contrary to the cost drivers for secondary distribution costs. The NCP demand allocator is used for distribution costs that are shared across a wide group of customers, such as substation costs and primary distribution lines. If a customer in one neighborhood reduces their load, this "freed-up" capacity can be used to serve another customer in a different neighborhood served by the same substation. However, this is not the case for secondary distribution that serves an individual customer or at most, is shared by a small group of customers. Therefore, it is not valid to allocate secondary distribution costs with total class NCP information.

Q. WHAT IS LOAD DIVERSITY?

A. Load diversity means that not all customers peak at the same time or day. Therefore, the composite peak demand for the whole class is less than the sum of the individual peak demands for each customer.

Q. IS DIVERSITY A VALID REASON FOR MR. DISMUKES' PROPOSAL?

A. No. The NCP is a composite peak demand for a large class of customers. There is significant load diversity among all of the customers in each class. This diversity reduces the combined costs for substation and primary distribution equipment for the class. This diversity does not reduce the costs of secondary distribution equipment

[7] Dismukes at 18.

for the class, which is sized to serve individual homes and cannot be shared with other homes or neighborhoods, despite the diversity of loads.

Q. WHAT DO YOU RECOMMEND ON THIS ISSUE?

A. I recommend that the Commission reaffirm the use of APS's current method for allocating secondary distribution costs in its COSS because the SIM allocator is reflective of the drivers for these costs. Staff witness Dismukes' proposal does not appropriately reflect the cost responsibility for each customer class and, therefore, should not be adopted.

Q. PLEASE ADDRESS AECC WITNESS HIGGINS' COSS CRITICISM.

A. The AZ Sun assets are APS-owned grid-scale solar facilities that were installed as part of approved renewable program plans as APS sought to achieve the ACC's Renewable Energy Standard and Tariff (REST) targets. These assets are 100% allocated to the retail jurisdiction and, like the $6 million in renewable costs recovered in base rates, should appropriately be included in the system benefits charge[8] cost category. The original $6 million in renewable program costs has been categorized as system benefits since its inception. The remainder of the costs were in the REST. The AZ Sun assets were transferred to base rates in the most recent rate case prior to this one and were just categorized incorrectly. In this case, APS corrected this error. AECC witness Higgins disagrees. However, I believe this is simply because AG-X customers must pay the system benefits charge but not the unbundled generation charge. APS believes that all customers, including those AECC represents, should pay for the AZ Sun renewable assets. AG-X customers should not be excluded from this charge.

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[8] As defined by the Commission in A.A.C. R14-2-1601.41, system benefits include Commission-approved renewable programs such as the AZ Sun program. APS's proposed treatment of AZ Sun assets is consistent with the Commission's System Benefit Charge requirements in A.A.C. R14-2-1608.

Q. WOULD ADOPTING ANY OF THESE CHANGES IN THE CURRENT COSS IMPACT APS'S PROPOSED RATE INCREASES.

A. No, even if allocation factors were changed in the COSS that created different results, APS still believes it is appropriate to use a proportional allocation of the overall bill impact to all classes of customers.

C. *Solar Advocates' Criticisms of the Company's COSS*

Q. PLEASE ADDRESS SEIA WITNESS LUCAS' CRITICISM.

A. SEIA witness Lucas' criticism is an attempt to re-litigate findings in the Commission's Cost and Value of Solar (VOS) Decision No. 75859. For example, the VOS decision found that residential solar customers should be evaluated as a separate class in a COSS, not analyzed as part of the overall residential class as recommended by SEIA. Also, in the VOS docket and in APS's last rate case, APS provided significant testimony justifying why the appropriate allocation method for rooftop solar customers should be based on site load and then the appropriate credits should be provided based on what costs solar customers actually offset. SEIA proposes this should be done using the delivered load[9], however, this method would require other costs be added back in for the services the rooftop solar customer is still receiving but no longer paying for in rates.

Q. DOES SEIA WITNESS LUCAS HAVE OTHER CRITICISMS OF APS'S COSS?

A. Yes, he does. All are invalid.

[9] SEIA witness Lucas conflates statements in the VOS decision referring to export energy and the successor program to net metering to support this position. Rather, this was in contrast to a buy-all/sell-all approach. Decision No. 75859, page 146 stated, "The record in this proceeding demonstrates that rooftop solar customers are partial requirements customers who export power to the grid, and we therefore find that rooftop solar customers are a separate class of customers."

Q. PLEASE EXPLAIN.

A. SEIA witness Lucas alleges APS COSS model is not transparent. However, it is a Microsoft Excel spreadsheet-based model. In addition, there was also a meeting held by APS to demonstrate the tool. SEIA is the only witness to raise this concern in this case.

SEIA's criticism is founded on a concern that APS did not provide everything back to the source, but that is simply not true. The model incorporates values from APS's accounting system as the starting point, and all that detail is included in the model. APS's audited financials are the source of all numbers in the model. The COSS model does not allow SEIA to audit APS's financial accounting system (which is already audited by an independent accounting firm), but then that is not its purpose. SEIA had access to APS's FERC Form 1 for 2018 and 10-Qs for the first and second quarter of 2019 to complete the Test Year if SEIA wanted to independently verify revenues from retail rates.

SEIA's transparency complaint results from the desire to allocate costs to residential solar customers using delivered load. SEIA's desire to manipulate the COSS model to incorporate this incorrect assumption is not an indication that the model is not transparent. Further, SEIA alleges APS is bound by a finding in a UNS Electric (UNSE) decision regarding the use of a residential subclass NCP for cost allocation to rooftop solar customers. APS has a much higher adoption rate of rooftop solar in the overall residential customer class than UNSE. The finding in the UNSE decision is specific to UNSE. APS's method is appropriate for APS, given its unique circumstances.

Q. PLEASE ADDRESS SEIA'S CRITICISM OF APS'S USE OF SITE LOAD IN THE COSS IN MORE DETAIL. HOW DID YOU DETERMINE IT WAS APPROPRIATE TO CREATE A SEPARATE RESIDENTIAL SUB-CLASS FOR RESIDENTIAL ROOFTOP SOLAR ENERGY AND DEMAND CUSTOMERS WITHIN THE RESIDENTIAL CUSTOMER CLASS?

A. It can be appropriate to create a new class or sub-class of customers for purposes of a COSS or setting rates if the service, load, or cost characteristics of the customer sub-group in question are sufficiently different from their current customer classification. Upon reviewing these characteristics for customers with solar, APS determined that sufficient differences exist for creating this sub-class of residential customers. That was true in the VOS docket, and it is even more true now. When evaluating the load characteristics of residential customers with and without rooftop solar, the peak demand – CP, NCP and SIM – and energy characteristics are very different for solar customers. In the Test Year, the average residential solar customer still needs about 74% of the capacity they used before they adopted solar and 37% of the energy. This is a significantly different profile than residential customers without solar, regardless of size.

APS had nearly 76,000 grandfathered residential solar customers and over 15,000 residential solar customers on the new Resource Comparison Proxy export rate by the end of the Test Year. The size of this residential solar customer sub-group combined with its vastly different load characteristics, warrant evaluating them as a separate sub-class which, again, was determined in the VOS.

Q. PLEASE EXPLAIN THE PROCESS THAT APS USED TO CREATE A UNIQUE RESIDENTIAL SUB-CLASS FOR RESIDENTIAL ROOFTOP SOLAR CUSTOMERS.

A. Consistent with the methodology I previously discussed:

- APS grouped residential solar customers currently on energy-based rate schedules, which includes customers both on inclining block and TOU rate schedules;
- APS separately grouped residential solar customers on demand-based TOU rate schedules;
- APS used the data for the residential solar customer's entire load at the home – load served both by APS and the customer's rooftop solar system – as the starting point for cost allocation to develop the CP, NCP, and SIM demand allocations, as well as the energy allocations;
- APS then explicitly credited the customer for:
  - All their self-provided production capacity based on a comparison to the APS-delivered customer load using both the four summer sub-class CPs and NCPs;
  - Their entire energy production, including both what the customer consumes on-site and what is delivered from the residential solar customer to the grid;
  - The avoided transmission cost based on a comparison to the APS-delivered customer load at the time of the four summer CPs;
  - The avoided primary distribution cost based on a comparison to the APS-delivered customer load at the time of the four summer sub-class NCPs; and
  - The avoided secondary distribution cost based on a comparison to the APS-delivered customer load at the time of the four summer sub-class SIMs.

This approach fully credits residential solar customers for all cost savings resulting from the capacity (production, transmission, and distribution) and energy supplied to the grid by their rooftop solar systems. The result is that the COSS analysis only allocates capacity and energy costs to residential solar customers based on what APS must provide. This analytical approach also captures the cost of providing grid services for the rooftop solar customer's export of energy and backup of the customer's self-supplied generation, including support for the starting of motors (*e.g.*, the inrush current associated with the starting of an air conditioning unit, which cannot be met by a solar array).

Q. BY USING A RESIDENTIAL SOLAR CUSTOMER'S ENTIRE LOAD AT THE HOUSE AS A STARTING POINT, AREN'T YOU CHARGING FOR SERVICES APS DOES NOT PROVIDE?

A. No, in fact, the exact opposite is true. It is true that APS does not supply the energy service when a residential solar customer's self-generation is supplying energy. But, the crediting process described above fully accounts for the customer's self-supply of this energy service. Moreover, although the residential solar customer supplies some of their own energy, APS continues to supply a host of backup and ancillary services that in turn require APS to build, operate, and maintain the bulk of its fixed infrastructure required to serve that residential solar customer. Beginning with a residential solar customer's entire site load and then explicitly crediting to that customer the value of the energy and capacity that they supply from their own rooftop solar system is the only transparent way to balance the benefits provided by rooftop solar systems on residential rooftops and the costs required to continue serving those customers with rooftop systems.

Q. PLEASE EXPLAIN FURTHER HOW THIS APPROACH COMPENSATES RESIDENTIAL SOLAR CUSTOMERS FULLY FOR THE BENEFITS THEY PROVIDE TO APS.

A. By comparing the entire load at the home to the remaining household load served by APS, we can determine the infrastructure that APS no longer needs to provide as a result of the solar system. Although a solar installation will have a certain maximum-production capability, that capability will only be realized at midday and only on sunny days. The load information reveals what actually occurred when the customer was consuming energy in contrast with the solar production at the same time. The alignment between when a residential customer needs power and when the solar system operates is not significant in APS's service territory. APS's peak loads persist in the summer months beyond sunset, and the maximum peak load occurs closer to sunset than midday.

The appropriate level of compensation for offsetting demand-driven infrastructure costs should be based on how effective the residential solar customer's solar system is at offsetting APS's peak loads. For example, the COSS indicates for a residential solar customer, the appropriate level of production demand credit is 26.3%, transmission capacity credit is 36.4%, distribution primary and substations capacity credit is 16.2% and distribution secondary capacity credit is 20.4%.

Likewise, the energy compensation in a COSS should reflect the actual fuel costs that APS avoids when a solar customer consumes less energy. The method described above uses the filed avoided fuel costs for all kWh produced by the rooftop solar system, which is a conservative proxy for the actual costs saved by APS.

Q. SEIA WITNESS LUCAS IS CRITICAL OF APS'S LOAD RESEARCH CENSUS AND HOW THAT DATA IS EXTRAPOLATED INTO OVERALL FERC FORM 1 SALES INFORMATION. IS THIS A VALID CRITICISM?

A. Absolutely not. APS's load research approach is superior to most utilities that still primarily use a load research sample and extrapolate that data into FERC Form 1 sales information. A utility has to start with actual sales in the Test Year. And any load research sample will require a method to convert the sample data into the full picture. APS's load research census uses customers' data if their interval data lines up with their billing meter reads and 100% of intervals for the 24-hour period are recorded. The information is then used in calculating the average customer for the day. Based on this method, APS has on average 1,065,132 customers in the census sample, versus a more typical load research sample of approximately 2%. Again, this criticism stems from SEIA's desire for the data to reflect delivered load for solar customers.

Q. SEIA ALSO MAKES REFERENCE TO A REGULATORY ASSISTANCE PROJECT (RAP) MANUAL ON COST ALLOCATION. DO YOU HAVE A PERSPECTIVE ON THE RAP MANUAL?

A. Yes, I do. The Regulatory Assistance Project (RAP) is not an unbiased industry consulting or academic group trying to revise cost allocation theories to improve the evaluation of distributed resources, as SEIA suggests. Rather, it is an advocacy group for energy efficiency and distributed solar resources. RAP's mission, as they clearly state, "is dedicated to accelerating the transition to a clean, reliable, and efficient energy future."[10] Therefore, their opinions should be viewed similarly to SEIA's – as an advocacy group offering viewpoints that seek to support their cause and benefit customers that adopt their preferred technologies. Similarly, the RAP

[10] Regulatory Assistance Project website home page, https://www.raponline.org/.

Manual should be considered to be an advocacy white paper, rather than a neutral how-to guide for utility cost studies.

Q. SEIA WITNESS LUCAS ALSO CLAIMS RESIDENTIAL ROOFTOP SOLAR CUSTOMERS ARE NO DIFFERENT THAN NON-SOLAR CUSTOMERS. IS THIS CORRECT?

A. No, it is not. As I indicated above, they are significantly different in their energy use characteristics. This claim was effectively debunked in the VOS docket, which is what led to the finding that rooftop solar customers should be evaluated as a separate class in a COSS because partial requirements customers are fundamentally different in their usage of the grid than full-requirements customers regardless of size.

Q. WHAT IS DELIVERED LOAD?

A. The electrical load of a solar customer can be separated into three components: 1) the total house load, or site load; 2) the portion of the site load that is served by the solar generator; and 3) the residual load that is served by the utility. The latter is referred to as "delivered" load.

Q. WHAT DOES SEIA WITNESS LUCAS CLAIM CONCERNING DELIVERED LOAD?

A. As I discussed above, SEIA witness Lucas asserts that the delivered load is the only portion that should be included in a COSS or any other type of economic evaluation of distributed solar generators. SEIA equates a solar generator to a cooktop or any other type of appliance, which would not require or warrant any special treatment in a COSS.[11] SEIA asserts that for either an appliance or a generator, the utility is only responsible for, and only incurs costs for, serving the delivered load.[12]

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[11] SEIA Direct Testimony of Kevin Lucas at 24.
[12] Lucas at 23.

Q. DO YOU AGREE?

A. No. An on-site generator is fundamentally different than an appliance, both in terms of the service requirements for a utility and the costs for those services. That is the entire point of my earlier discussion on why solar customers are separated into a distinct customer class in the COSS and why a different method is needed for assessing the costs for the solar class.

Q. PLEASE EXPLAIN.

A. Customers with on-site generation, also referred to as partial requirements customers, have always warranted special rate treatment. Because the customer generates their own power and potentially exports power to the grid, special rate provisions are necessary to compensate the customer for the exported power, provide backup service for the generator, and to appropriately recover the costs of the grid services provided by the utility. These services go well beyond the simple cost of service for the delivered load claimed by SEIA witness Lucas.

Q. PLEASE CONTINUE.

A. Because of APS's increased responsibilities and costs for serving partial-requirements customers, the Commission has authorized special rate provisions and programs for these customers for decades. In the last rate case, the legacy residential net metering program which incented the early adoption of solar generation, was frozen because it over-compensated solar customers for the exported power, did not adequately recover costs for providing backup service, and significantly under-recovered the costs for the grid services provided by the utility. These issues, coupled with the explosive growth in solar adoption, resulted in the potential for over $1 billion of under-recovered costs to be shifted to other residential customers.

Q. SEIA WITNESS LUCAS ALSO CLAIMS THAT THIS COST EVALUATION SHOULD BE BASED ON MARGINAL COSTS. DO YOU AGREE?

A. No, not generally in a rate case evaluation. While certain rate design issues can be informed by marginal costs, such as the magnitude of monthly service charges or the TOU price ratios, a rate case is fundamentally focused on the recovery of average, embedded costs for a historic test year. Therefore, the compilation and allocation of costs in a COSS and the reflection of those costs in rate design primarily involves embedded cost, rather than marginal cost, information. While a new approach is needed for evaluating solar customers and appropriately reflecting the additional costs to serve them, as I have outlined above, those costs should generally use test-year embedded cost information.

Q. LASTLY, SEIA WITNESS LUCAS OBJECTS TO THE METHOD FOR ALLOCATING GENERATION COSTS TO SOLAR CUSTOMERS. WHAT ARE YOUR THOUGHTS?

A. APS evaluates the generation capacity costs, also referred to as production capacity, for serving solar customers by first allocating those costs to the solar classes based on the site load using the A&E method, similar to other residential classes, and then crediting the service cost reduction attributable to the solar generator based on coincident peak and non-coincident peak information. Mr. Lucas claims that this approach is internally inconsistent and, therefore, incorrect.

Q. DO YOU AGREE?

A. No. SEIA witness Lucas offers no reasoning, other than that the two methods are different, to support his conclusion. In fact, two different allocation methods are needed to accurately reflect the cost impacts for production capacity for customers with on-site generation. The A&E method reflects the overall generation costs needed to serve the entire site load, from APS's entire portfolio of power plants – including baseload nuclear and coal plants to peaking natural gas plants. However, the capacity cost savings from adding solar generation is more appropriately assessed using an allocator that reflects the specific capacity impacts provided from on-site generation, which are driven by the availability of the generator at the time of APS's system peaks.

This two-method allocation approach is conceptually the same as the cost studies that support the partial-requirements rates for general service customers. For those rates, the customer's unbundled generation charges in their base rate is based on a general A&E cost allocator, while the specific rates for the services needed to back up and support the on-site generation are based on the generator's peak impacts.

X. GENERAL SERVICE RATE DESIGN

Q. DID YOU REVIEW THE COMMENTS OF OTHER PARTIES CONCERNING APS'S GENERAL SERVICE RATES?

A. Yes. SEIA was the only party that provided comments and proposals on APS's general service rates. They propose several changes to the general service E-32 rates, which include: 1) removing the declining block demand and energy structure; 2) removing the demand ratchet for rate E-32 L,[13] 3) changing the demand charge for rate E-32 S; and 4) restructuring all of the rates so that high load factor customers on the border of two rates can achieve a higher bill savings when they reduce their demand.[14]

Q. WHAT IS YOUR GENERAL RESPONSE TO SEIA'S PROPOSALS?

A. APS opposes each of SEIA's proposals because they do not appropriately reflect the cost of service for these customer classes. Instead, they unjustifiably favor customers that adopt SEIA's favored technologies and shift costs to other customers by raising their rates and bills. APS believes that rates should be technology

[13] Lucas at 116.
[14] Lucas at 120.

agnostic; the bill savings from adopting a certain technology should be commensurate with the cost savings provided back to the grid. APS's commercial rates, as presently designed, do a good job of addressing this important objective. SEIA's proposals do not. They essentially create a subsidy for certain technologies, while shifting costs to other customers. I note that no commercial customer or group that represents commercial customers are offering any similar proposals.

Q. LET'S FIRST DISCUSS THE DECLINING BLOCK DEMAND CHARGE.

A. Sure. Because the E-32 rates serve a wide variety of customers with different demands and usage characteristics, the unbundled distribution charges are separated into two components. The first component recovers a basic level of distribution service for "hook-up" costs and other general costs, some of which could alternatively be recovered through a monthly customer charge. The charge for this tier is applied to a customer's first 100 kW of demand each month. The second component recovers additional distribution costs that increase as a customer's load increases. The charge for this tier, which is lower than the first-tier charge, is applied to the customer's monthly demand above 100 kW. As a result, larger customers are charged a lower average demand rate than smaller customers, which reflects their lower average cost of service.

Q. WHY DO THINK SEIA WITNESS LUCAS IS PROPOSING TO ELIMINATE THIS RATE FEATURE?

A. Undoubtably, eliminating this feature would potentially increase the avoided demand charge for larger customers that might consider adopting certain technologies that target demand reduction, such as behind-the-meter solar plus storage. I also note that SEIA'S proposal would also, without intention, decrease the avoided demand charge for smaller customers who seek to adopt similar demand-reducing technologies.

Q. WHAT DO YOU RECOMMEND?

A. SEIA's proposal should be rejected because it is not reflective of cost of service. This feature helps ensure the rate can be used to serve a wide variety and size of commercial customers.

Q. NOW LET'S DISCUSS THE ENERGY CHARGES FOR RATES E-32 S AND E-32 M, WHICH SEIA OPPOSES.

A. Rate E-32 S serves small-sized general service customers with monthly demands of 21 to 100 kW, while E-32 M serves medium-sized commercial customers with monthly demands of 101 to 400 kW. The unbundled generation charges for both rates have a unique design called a "load-factor" or "times-use" rate structure. It is not, strictly speaking, a declining block energy rate, as SEIA states, but rather a rate structure that combines a demand charge and energy charge into a single rate component.

Q. PLEASE EXPLAIN.

A. The unbundled generation charges for general service rates typically include two components – a demand charge, which recovers the capacity cost of generation power plants, and an energy charge, which recovers the cost of fuel and variable O&M. The load factor design uses a two-tiered energy charge design and incorporates the demand charge into the first-tier energy charge. In addition, the tiers are based on a certain amount of kWh usage per unit of kW demand, instead of merely being a traditional declining-block energy rate, as referenced by SEIA witness Lucas, in which the tiers are based on total kWh usage.

Q. CAN YOU PROVIDE AN EXAMPLE?

A. Yes. Consider a customer served under the E-32 M rate that uses 110,000 kWh and 300 kW in a month. The billing units, unbundled generation rates for the two kWh tiers and billed amounts, are shown in Table 2 below, under "current rate design." The tier 1 kWh energy charge applies to 200 kWh per kW or 60,000 kWh (200 X

300). All of the additional 50,000 kWh are billed under the tier 2 energy charge. The charges for each tier recover $0.04965 per kWh of energy-related costs. The Tier 1 charge also recovers $0.04103 per kWh of generation capacity costs, which is the Tier 1 energy charge minus the Tier 2 energy charge.

Q. WHAT WOULD THE RATE BE IF IT USED A DEMAND CHARGE INSTEAD OF THE TIMES-USE APPROACH?

A. If the rate were redesigned to recover the generation capacity costs through a kW demand charge, instead of through an embedded kWh load-factor tier, the demand charge would equal S8.206 per kW, which is the $0.04103 per kWh of embedded capacity charge in Tier 1 converted to a kW charge by multiplying it by 200 kWh ($8.206 = $0.04103 X 200 kWh). This conversion is displayed below in Figure 1 below. Please note that these alternative charges are illustrative – they would have to be adjusted slightly to assure that the resulting revenue is neutral for the entire E-32 M customer class.

Figure 1. Unbundled Demand Charge for Rate E-32 M Summer Month

Tier 1 kWh	$	0.09068
Tier 2 kWh	$	0.04965
Demand Component	$	0.04103
Converted to kW charge	$	8.206

Q. WOULD THE BILL BE THE SAME UNDER BOTH RATE DESIGNS?

A. Not necessarily. The example shown in Table 1 results in the same monthly bill under either rate design. However, this result will vary according to the actual customer's load patterns and the comparative amount of energy and demand consumed in a month. Some customers would pay more under the alternative design, others would pay less.

Table 2. Rate E-32 M, Proposed Unbundled Generation Rates (Summer)

Currently Proposed Rate Design

	Units	Rate	Bill
Tier 1 kWh	60,000	$ 0.09068	$ 5,440.80
Tier 2 kWh	50,000	$ 0.04965	$ 2,482.50
			$ 7,923.30

Alternative Rate Design

	Units	Rate	Bill
kW demand	300	$ 8.206	$ 2,461.80
kWh energy	110,000	$ 0.04965	$ 5,461.50
			$ 7,923.30

Q. HAVE ANY CUSTOMERS OR CUSTOMER GROUPS RECOMMENDED THIS CHANGE?

A. No. The current rate design fairly recovers generation capacity costs from a rate class that has a wide range of customer sizes and usage patterns.

Q. WHAT DOES APS RECOMMEND FOR RATES E-32 S AND E-32 M?

A. Conceptually, APS does not oppose converting the unbundled generation charges in rates E-32 S and E-32 M from a load-factor-based design to a traditional demand and energy charge design. However, APS does not support this rate change at this time because SEIA witness Lucas has not provided any compelling reasons for making this change, no customer groups are proposing this change, and the change would create disparate bill impacts for customers, which have not been investigated.

In addition, APS would be opposed to simply combining the two tiers of energy charges into a simple average kWh rate, without converting the embedded demand component into a demand rate. Combining the two energy charges into a single rate would simply recover all of the generation capacity costs through a kWh rate, which would not be reflective of the cost of service and would be a flawed approach to rate design.

Q. WHAT DOES SEIA PROPOSE CONCERNING THE DEMAND RATCHET FOR RATE E-32 L?

A. SEIA proposes to eliminate this feature of the rate.[15]

Q. WHY IS SEIA PROPOSING THIS CHANGE?

A. Again, this proposal is self-serving for SEIA. It seeks to increase the economic benefit for customers who adopt certain technologies supported by SEIA, while raising the demand rates and bills for other customers.

Q. HOW WOULD SEIA'S PROPOSAL INCREASE THE RATES FOR CUSTOMERS THAT DO NOT ADOPT SEIA'S PREFERRED TECHNOLOGIES?

A. The demand ratchet feature is a cost-based rate component that helps to match the demand component of each customer's bill with their actual cost of service. If the demand revenue for some customers is unjustifiably reduced, the costs will be shifted to other customers in the same class through higher demand rates.

Q. WHAT IS A DEMAND RATCHET?

A. A demand ratchet is a rate feature that seeks to fairly recover a customer's demand costs through monthly demand charges, even though the costs are primarily driven by the customer's demand in the core summer months. The demand charges could alternatively be applied only to the summer bills, but that would result in very uneven monthly bills, which would be very high in the summer. In addition, some demand-related costs are driven by a customer's demand in all months of the year.

[15] Lucas at 116.

Q. ARE RATCHETS COMMONLY USED IN THE UTILITY INDUSTRY?

A. Yes. Demand ratchets are a common feature in rates for large and extra-large commercial and industrial customers across the utility industry.

Q. HOW DOES A RATCHET WORK?

A. On each monthly bill, the customer pays the higher of their actual metered demand or 80% of the highest demand in the previous summer. If a customer has a relatively steady load throughout the months, the ratchet would have no impact. If the customer's demand falls off significantly in the winter months, the ratchet would ensure that the demand-related costs would be recovered from that customer, and not shifted to other customers.

Q. DOES APS SUPPORT SEIA'S PROPOSAL TO ELIMINATE THE RATCHET?

A. No. SEIA has not provided any compelling reason for eliminating the ratchet feature. SEIA's proposal is simply self-serving and unjustifiably shifts costs to customers that do not adopt their preferred technologies. In addition, I note that no customers or customer groups are proposing this change.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS ON SEIA'S PROPOSALS ON GENERAL SERVICE RATES.

A. APS does not support any of SEIA's proposals for general service rates. SEIA does not offer any valid reasons for making these changes. They are simply self-serving and seek to advantage customers that adopt their preferred technologies and shift costs to other customers by increasing demand charges and bills. In addition, no customers or customer groups are proposing these changes.

Q. WHAT DOES SEIA PROPOSE FOR APS'S E-32 L STORAGE PILOT RATE?

A. SEIA proposes to modify the E-32 L Storage Pilot rate by eliminating the minimum storage requirement, changing the on-peak hours to 2-6 p.m., and changing the demand charge structure for on-peak and "remaining" hours.[16]

Q. DID SOLAR PARTIES DEVELOP AND PROPOSE THIS RATE?

A. Yes. SEIA contends that the storage pilot rate was designed by APS.[17] However, this is incorrect and misleading. In fact, the E-32 L Storage Pilot rate was proposed by solar parties as part of APS's last rate case and ultimately approved by the Commission. They patterned the rate after a storage rate from another utility.

Q. THEN WHY IS SEIA SEEKING TO SIGNIFICANTLY CHANGE THE RATE AT THIS TIME?

A. Presumably, the solar parties' previous rate design was ineffective at driving the adoption of storage technology.

Q. DO YOU AGREE WITH SEIA'S PROPOSED MODIFICATIONS?

A. APS agrees to further investigate the storage rate issue, but we do not necessarily agree with SEIA's proposals; some are invalid and should not be adopted, and others will require further investigation.

Q. PLEASE EXPLAIN.

A. The proposal for a 2 p.m. to 6 p.m. on-peak period does not reflect the critical hours on APS's system and is only self-serving to promote distributed solar. This issue is further discussed in the Rebuttal Testimony of APS witnesses Hobbick and Albert. Therefore, this proposal should be rejected. In addition, SEIA's proposal to eliminate the requirement that a customer adopt energy storage to qualify for the rate should be rejected. The suggestion is nonsensical; why in the world would you ever develop an energy storage rate that does not require energy storage? Furthermore,

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[16] Lucas at 130-31.

[17] Lucas at 121.

APS believes that a reasonable minimum storage requirement is appropriate to prevent a customer from “gaming” the rate schedule by installing a de minimis amount of storage technology.

However, the Company believes that the demand-rate structure and other rate-design components can be investigated as long as they are reflective of cost of service and not just intended to advantage customers that adopt energy storage at the expense of other customers.

Q. ASBA/AASBO HAVE PROPOSED SEVERAL CHANGES. PLEASE DISCUSS THEIR RECOMMENDATION REGARDING THE SCHOOLS TOU RATES.

A. ASBA/AASBO propose to modify the Schools TOU rate, which presently has three seasons (Winter, Summer, and Summer Peak) and three time periods (On-Peak, Off-Peak, and Shoulder-Peak). They propose to eliminate the Shoulder-Peak time period and use the off-peak price for those shoulder hours. While APS is not opposed to removing the shoulder-peak price, the off-peak price would also have to be revised to ensure that the change was revenue neutral. However, if parties desire to change the Schools TOU rate, I would recommend to further revise the rate beyond what is described by ASBA/AASBO witness Travis Sarver, to be more consistent with other general service and irrigation rates. Such revisions could include, for example, changing the on-peak period to be 3 p.m. to 8 p.m., Monday through Friday, and reviewing the appropriateness of the three seasons in the Schools TOU rate.

Q. WOULD THESE TYPES OF RATE REVISIONS CREATE DISPARATE BILL IMPACTS FOR INDIVIDUAL SCHOOLS?

A. Yes. If the Schools TOU rate were revised by either ASBA/AASBO’s proposal or by the further modifications I have discussed, the changes would result in disparate bill impacts for individual schools. Some bills would increase, others would decrease beyond the impact of the general revenue change authorized in this proceeding.

Q. ASBA/AASBO ALSO PROPOSES TO ALLOW SCHOOLS WITH SOLAR TO USE THE RESOURCE COMPARISON PROXY (RCP) AS AN ALTERNATIVE TO NET METERING. DO YOU SUPPORT THIS SUGGESTED CHANGE?

A. No, I do not support this change. The VOS proceeding was about addressing the cost shift resulting from net metering for residential rooftop solar customers. The result was the RCP method for energy that is exported to the grid, at any time, and using the retail rate to offset self-consumption. Schools still have the ability to net meter, and the VOS decision and resulting RCP for export energy is simply not applicable to schools.

Q. IN ADDITION, ASBA/AASBO PROPOSES SCHOOLS BE ALLOWED TO AGGREGATE THEIR METERS ACROSS THE SCHOOL DISTRICT. WHAT ARE YOUR THOUGHTS ON THIS?

A. APS strongly opposes this aggregation recommendation. APS presently allows a school to totalize its loads on a contiguous campus in accordance with its Service Schedule 4 - Totalized Metering of Multiple Service Entrance Sections at a Single Site. This form of totalization is reasonable. However, aggregating loads across a school district is not appropriate. Each campus location has different electric infrastructure. The specifics of cost causation, cost allocation, and the design of rates takes this into account. A campus can be considered a unique customer, but a customer with multiple locations constitutes many customers. It is inappropriate to aggregate school loads across a district that has multiple school campuses. Lastly, the proposed rates and charges are designed to collect the targeted revenue without aggregation. ASBA/AASBO witness Sarver has a simple example where he illustrates the benefits of aggregation but ignores that fact that the rates would have to be redesigned to collect the target revenue – essentially reclaiming his computed savings.

XI. CONCLUSION

Q. WHAT CONCLUSIONS DO YOU HAVE BASED ON YOUR REBUTTAL TESTIMONY?

A. The Commission should approve APS's conservative fair value rate of return. The mechanics of the calculation are based on those proposed by ACC Staff and adopted by the ACC in the 2007, 2010 and 2015 test year rate filings made by APS that resulted in Decision Nos. 71448 (Dec. 30, 2009), 73183 (May 24, 2012), and 76295 (Aug. 18, 2017).

The Commission should approve APS's proposed AEM.

The Commission should approve APS's COSS that is used to support the Company's rate design in the Company's application, as well as the jurisdictional allocation of costs.

Lastly, the Commission should reject intervenors' proposals regarding the AG-X /AG-Y programs and approve APS's new rate rider proposal AG-Y. The Commission should reject SEIA's and ASBA/AASBO's recommendations regarding general service rate design.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Calculation of Fair Value Increment

	Adjusted Test Year Capital Structure	Amount	%	Cost Rate	Weighted Avg
1.	Long-Term Debt	$ 4,726,125	45.33%	4.10%	1.86%
2.	Preferred Stock	-	0.00%	0.00%	0.00%
3.	Common Equity	5,700,968	54.67%	10.00%	5.47%
4.	Short-Term Debt	-	0.00%	0.00%	0.00%
5.	Total	$ 10,427,093	100.00%		7.33%

	Capital Structure with 1.0% FV Increment	Amount	%	Cost Rate	Weighted Avg
6.	Long-Term Debt	$ 4,032,678	32.75%	4.10%	1.34%
7.	Preferred Stock	-	0.00%	0.00%	0.00%
8.	Common Equity	4,863,590	39.49%	10.00%	3.95%
9.	Short-Term Debt	-	0.00%	0.00%	0.00%
10.	FVRB Increment	3,418,936	27.76%	0.80%	0.22%
11.	Total	$ 12,315,204	100.00%		5.51%

	Fair Value Increment Calculation	Fair Value	Original Cost
12.	Rate Base	$ 12,315,204	$ 8,896,268
13.	Rate of Return	5.51%	7.33%
14.	Required Operating Income	$ 679,050	$ 652,096
15.	Adjusted Operating Income	648,726	648,726
16.	Adjusted Operating Income Deficiency (line 14 - line 15)	$ 30,324	$ 3,370
17.	Revenue Conversion Factor	1.3346	1.3346
18.	Increase in Base Revenue Requirements (line 16 * line 17)	$ 40,470	$ 4,497
19.	Fair Value Increment	$ 35,973	
20.	RCND Rate Base	$ 15,734,140	

Advanced Energy Mechanism (AEM) Plan Cost Recovery Term Sheet

Purpose	To provide for timely cost recovery of the capital carrying cost and expense of APS clean energy plan investment, including energy efficiency (EE) expenses, and lost fixed costs associated with EE and distributed generation (DG) revenue requirements which are not already recovered in base rates or through another Arizona Corporation Commission (Commission) approved adjustment. Clean energy resources are defined as non-carbon emitting resources but excludes nuclear energy.
Authorization	Integrated Resource Plan (IRP) Action Plan or Clean Energy Implementation Plan approval by the Commission and robust Request for Proposal (RFP) process – acquisitions that comply with the IRP Action Plan and RFP process. The IRP process would determine the prudence of the IRP Action Plan, and the process prescribed in Energy Rules would determine the prudence of the Clean Energy Implementation Plan.
Cost Recovery of APS Owned Resources, EE Investment and Coal Community Transition (CCT) Cost	An Advanced Energy Mechanism (AEM) will recover the capital carrying costs of approved clean energy plan investment, including APS-owned newly constructed or acquired plants, EE expenses, lost fixed costs associated with EE and DG revenue requirements and Coal Community Transition cost. The AEM process will determine prudence of APS's execution of the IRP Action Plan and Clean Energy Implementation Plan.
Lost Fixed Costs (LFC)	Lost Fixed Costs (LFC) recovered will be consistent with the current accounting for LFC. In future rate cases (not the current rate case), APS may propose changes to the LFC recovery accounting.
Cost Recovery of Resources Resulting from Purchased Power Agreements (PPA)	Purchase Power Agreement (PPA) resources will be recovered through the Company's Power Supply Adjustor (PSA), including storage PPAs. PPAs with recovery presently split between the Renewable Energy Adjustment Charge (REAC) and PSA would move completely to the PSA.
AEM Adjustor Process	Annual filing and implementation as specified in a Plan of Administration, including EE investment plan. In each rate case, the AEM will be reset and APS-owned resource investments will be moved into base rates.
Key Parameters of Capital Carrying Costs	Capital Carrying Costs consist of (1) Return on the Qualified Net Plant calculated based on the Company's Weighted Average Cost of Capital (WACC) approved by the Commission in its most recent rate case plus a return on the fair value increment (if any) for the Qualified Net Plant; (2) depreciation expense; (3) income taxes; (4) property taxes and (5) associated operations and maintenance expenses (O&M).
Year-over-Year Annual Adjustor Cap	The AEM will not increase by more than $0.005 per kWh in any annual adjustment process. Any amounts over the annual cap would be held over to a subsequent adjustment.
Balancing Account	The AEM will have a balancing account that will track revenues versus costs, as well as a true-up of budgeted to actual costs.
Earnings Test	As part of each filing, APS will file an earnings test based on the Commission's jurisdictional portion of the most recent FERC Form 1, with rate base, operating revenue and expense adjustments adopted in the most recent rate case. The earnings test will determine what portion of the AEM will be recoverable each adjustment cycle.

AEM Timing	Stakeholder Engagement (including EE plan and LFC forecast): February - May Filing: June 1 Effective: January 1
AEM Approval	ACC – Open Meeting
AEM Revenue Allocation	Equal across rate classes, kW charge for customers on kW rates, and kWh charge for customers on energy-only rates.
Other Adjustor Rates	APS retains all current adjustors: PSA, Transmission Cost Adjustment (TCA), Environmental Improvement Surcharge (EIS) and Tax Expense Adjustment Mechanism (TEAM), Lost Fixed Cost Recovery mechanism (LFCR), REAC and Demand Side Management Adjustment Clause (DSMAC). AEM will replace LFCR, REAC and DSMAC over time as they are reset in the future.
Adjustor and Base Rate Transfers	A revenue-neutral portion of REAC costs will be moved to base rates and the PSA. A revenue-neutral portion of DSMAC costs will be moved to base rates.

ATTACHMENT 8

REBUTTAL TESTIMONY OF MONICA WHITING

On Behalf of Arizona Public Service Company

Docket No. E-01345A-19-0236

November 6, 2020

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REBUTTAL TESTIMONY OF MONICA WHITING
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-19-0236)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, JOB TITLE, AND BUSINESS ADDRESS.

A. My name is Monica Whiting. I am Vice President of Customer Experience and Chief Customer Officer for Arizona Public Service Company (APS or Company). I am responsible for delivering key customer services and operations at APS with a dedicated focus on the Customer Experience. This includes the Care Center, Revenue Operations, Customer Experience Strategy, Solutions and Initiatives, and Key Account Management. My business address is 400 N. 5th Street, Phoenix, Arizona 85004.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. My background and experience are set forth in Attachment MW-1RB to this Rebuttal Testimony. I have worked in the utility industry for nearly 30 years, at public power and investor-owned utilities in different states throughout the country. My experience includes working for utilities that performed in the top quartile of customer satisfaction nationally, as well as utilities that transformed to successfully move up to the top quartile. Throughout my career, my focus has been on customer experience, communications, and marketing. I joined APS in July 2020 because I was inspired by APS Chief Executive Officer Jeff Guldner and Chief Operating Officer Daniel Froetscher and their commitment to APS customers and Arizona. The Company's Executive Management is laser focused on putting customers at the center of everything APS does. I wanted to join them in advancing the APS customer experience.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS MATTER?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to recommendations and comments made by Staff and intervenors in this case on topics involving customer satisfaction, simplification of customer bills, education and outreach, limited-income programs, and reporting, as well as to discuss APS's vision for the future in some of these key areas.

II. <u>SUMMARY</u>

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. APS is committed to improving all aspects of customer service, including how the Company educates customers and the tools provided to them; working with stakeholders and customer research has become, and will remain, an important part of that process. Specifically, in my testimony I address the following topics:

- Simplifying APS's residential rate offerings to better differentiate between rates, including providing a flat rate option for all customers.

- With the input of customers and stakeholders, APS intends to redesign, simplify, and enhance all customer bills.

- In response to the COVID-19 pandemic and in collaboration with its low-income assistance agency partners, APS has taken action to assist those impacted by the pandemic and believes accepting certain proposals from Wildfire will further improve programs to assist limited-income customers.

- APS's Customer Education and Outreach Plan (CEOP) from the last rate case was not perfect, but it is not the "failure" that intervenors make it out to be, and while APS would prefer to focus on working together to make the future better, the Company cannot leave erroneous assertions unrebutted because they serve as the basis for intervenor recommendations. With that in mind, I include a report from Guidehouse (a leading global provider of consulting services to the public and commercial markets with expertise in the electric utility industry, utility education and outreach best practices, and behavioral science) to rebut the Alexander Report and to help incorporate best practices in our future customer education and outreach.

- Numerous intervenors discussed increased reporting requirements. I agree that transparency is vital to continued improvement in customer service; however, not all recommended reporting requirements are appropriate. Therefore, I recommend a reporting package I believe appropriately addresses the interests of stakeholders.

III. <u>FOCUS ON CUSTOMER EXPERIENCE</u>

Q. WHAT IS YOUR PLAN FOR DELIVERING AN INDUSTRY-LEADING CUSTOMER EXPERIENCE AT APS?

A. APS's goal is to deliver year-over-year improvement in overall customer satisfaction by advancing to industry-leading customer experience standards through a top-quartile ranking among other large investor-owned utilities. APS will take a holistic approach to all drivers of customer satisfaction informed by customer research, such as: JD Power and Associates, behavioral science (which considers the values and preferences that factor into how customers make choices), and best practices in prioritization and implementation. APS will focus on reliability and outage communication, value for the price paid, billing and payment, corporate citizenship, communications, and customer care, which includes the customer's phone and digital experience. APS will establish a formal customer experience strategy, an internal customer experience council, annual customer improvement workplans, and a Voice of the Customer program to capture customer research and insights. APS will continue to monitor, assess, and realign as customer expectations, technology and best practices evolve. The rest of my testimony discusses some of the ways the Company plans to do this moving forward, in conjunction with stakeholders.

IV. SIMPLIFICATION OF RESIDENTIAL RATE PLANS

A. *APS proposes to consolidate and simplify rates by offering three rate options for all non-solar residential customers.*

Q. IS APS PROPOSING ANY RATE CHANGES TO MAKE RESIDENTIAL SERVICE PLAN OPTIONS SIMPLER AND CLEARER FOR CUSTOMERS?

A. Yes. In response to feedback from customers and multiple intervenors, and to make it easier for customers to select a rate plan that meets their needs, the Company is proposing simplifying its rate structures and consolidating similar rate plans. The proposal includes three clear and distinct rate options: a flat rate, a time-of-use (TOU) energy-only rate, and a TOU-with-demand rate. Under this proposal customers will have access to, and the ability to choose among, these three rate structure types irrespective of their amount of usage. All solar customers will continue to have the option of choosing a TOU or demand rate. To effectuate the goal of simplification and move to three rate options, APS proposes eliminating the mandatory 90-day TOU rate trial period for new customers and consolidating the flat rate plans (the R-Basic family of plans) into one rate with multiple pricing tiers that can accommodate customers irrespective of usage size. Thus, customers who use on average more than 1,000 kWh per month would now have a flat rate option. This change also eliminates the annual rate reassignment from a standard rate plan to a TOU plan if the customer's annual average monthly consumption exceeds 1,000 kWh. Additional details about these changes are provided in the testimony of APS witness Jessica Hobbick.

Q. VARIOUS INTERVENORS AND COMMISSIONERS HAVE RECOMMENDED THAT APS CHANGE THE NAMES OF RESIDENTIAL RATE PLANS. DOES APS PLAN TO RENAME THE RESIDENTIAL RATE PLANS?

A. Yes. In conjunction with the proposed simplification of the residential rate plans, APS is working on a plan to rename them.

Q. BRIEFLY EXPLAIN THE PROCESS APS WILL USE TO DEVELOP NEW NAMES FOR RATE PLANS.

A. APS will develop new rate plan names based on customer research. The naming process will be a customer-focused, data-driven effort which includes rigorous customer research and stakeholder input.

Q. WHAT WILL THE OPPORTUNITIES BE FOR CUSTOMERS AND STAKEHOLDERS TO PROVIDE INPUT INTO THE RENAMING PROCESS?

A. APS will engage with stakeholders via monthly meetings and customers through the Customer Advisory Board.

B. *Customer Tools*

Q. STAFF WITNESS MATT CONNOLLY INCORPORATES RECOMMENDATIONS FROM THE ENERGYTOOLS REPORT FOR NEW GRAPHICS AND WAYS TO PRESENT CUSTOMER INFORMATION. DO YOU AGREE WITH THOSE RECOMMENDATIONS?

A. The Company is committed to providing useful, transparent, and easily understandable information to customers about energy usage. The Company supports many of Staff's recommendations and is currently developing or has already implemented, the following:

Figure 1

Staff Recommendations and APS's Implementation Status

Recommendation	Status
An application or graphic showing customers their level of usage, peak usage, including specific recommendations, and how to manage usage.	In progress. APS is currently developing an Energy Estimator tool that will allow customers to select different configurations of home sizes, seasons, rate plan types, and detailed information on how they use appliances, to see how the changes can impact the amount and cost of their usage or demand.
High usage alerts with the ability for customers to set their alert threshold either by dollar amount or consumption.	Today, APS customers can set alerts to notify them of high usage and estimated month-to-date billing costs.
Information on appliances and how to estimate peak demand.	In progress. Information on appliances and how to estimate demand will be part of the Energy Estimator Tool. Also, APS recently launched the APS Marketplace, which will offer customers energy-efficient appliances and education on how to reduce energy use.
Graphics/visuals for customers on peak usage estimation.	APS is currently looking at various tools, including personalized emails, that will offer energy tips to help customers shift their energy use and save on energy costs.

Additionally, the Company is researching infographics, language, and visuals to improve rate plan descriptions, explanation of the peak and off-peak hours, and the concept of demand and demand charges.

Q. DOES APS HAVE ENERGY USAGE AND DEMAND THRESHOLD ALERTS AVAILABLE TO CUSTOMERS?

A. Yes. Currently, residential and commercial customers can opt into several different types of usage alert thresholds and be notified by either email or text when that threshold is reached. The customer can set unique thresholds for on-peak usage, total usage, and demand. Customers can sign up for these alerts through aps.com to choose the alerts most helpful to them and their lifestyle. In addition, customers can set alerts for estimated bill (cost) thresholds, outages and a three-day notice prior to bills being due.

Q. IS APS CONSIDERING A GRAPHIC/VISUAL FOR CUSTOMERS' PEAK USAGE ESTIMATION?

A. APS is currently reviewing additional graphic elements for the website and other customer communication channels to provide customers with information in a meaningful way. Any new functionality will be tested with customers, including through the Customer Advisory Board and stakeholder group, before implementation.

Q. THE SIERRA CLUB HAS RECOMMENDED THAT APS IMPLEMENT "GREEN BUTTON" CONNECT-MY-DATA FUNCTIONALITY TO ALLOW CUSTOMERS TO MORE EASILY PROVIDE THEIR ENERGY USAGE DATA TO THIRD PARTIES, SUCH AS SOLAR PROVIDERS. WHAT IS APS'S POSITION?

A. Currently, APS customers can view their usage data online or download it into an Excel spreadsheet. If a customer wishes to provide that information to others, he or she can provide guest access to his or her account or send the Excel data to a third-party of choice. For customers who wish to have another way to share their data, APS is working on implementing "Green Button" and plans to have this functionality by the end of 2021.

V. RESIDENTIAL BILL REDESIGN

Q. DOES APS STILL INTEND TO SIMPLIFY ITS RESIDENTIAL BILLS?

A. Yes. APS is working to redesign and improve the customer bill based on customer research, industry best practices, and customer feedback about what information would be most helpful. Since the rate case application was filed, APS has expanded the project to encompass the redesign and enhancement of all residential and commercial bill presentations, both paper and electronic. The goal of this project is to design a bill that:

- Is easy to read and understand;
- Provides customers with the information they would like to have to manage their energy usage and monthly bill;
- Is delivered to customers using their channel of choice (*e.g.*, print, aps.com, electronic);
- Provides customers with a bill experience consistent in language, look and feel with the experience on other APS communication channels (*e.g.*, website, app, etc.); and
- Incorporates best practices from the utility and other relevant industries for bill presentment.

To accomplish these objectives, APS has partnered with International Business Machines (IBM) to leverage IBM's extensive experience in bill redesign projects, both within and beyond the utility sector, designing for the customer and user experience and based on customer and market research.

Q. WILL STAKEHOLDERS BE A PART OF THE BILL REDESIGN PROCESS?

A. Absolutely. The project plan includes multiple opportunities for customer and stakeholder insight through research, interviews, workshops, focus groups, and surveys. APS will solicit input from a diverse sample of its customer base. The design process will be iterative to incorporate feedback as it is provided and will include testing a prototype with customers and stakeholders focus groups.

Q. WHAT IS THE CURRENT STATUS AND TIMELINE FOR THE EXPANDED BILL REDESIGN PROJECT?

A. Bill redesign projects can take from 12 to 18 months, depending on the level of input, review, and complexity. Thus far, APS and IBM have held several one-on-one interviews with stakeholders and sought input from our Customer Advisory Board to gather their initial feedback for the design process. APS expects to have a proposed bill design by the second quarter of 2021, after which it will work to complete the technical implementation and provide the necessary change management. Final implementation is currently expected around the end of 2021. This implementation schedule is aggressive, and its timely completion will depend on final design and presentment requirements based on customer and stakeholder input. APS will keep the Commission informed throughout the redesign and implementation process.

Q. DID YOU REVIEW THE TESTIMONY PRESENTED BY RUCO WITNESS FRANK RADIGAN AND SIERRA CLUB WITNESS CHERYL ROBERTO REGARDING CUSTOMER BILL FORMATS?

A. Yes. RUCO makes suggestions it believes will simplify the bill and recommends that the Company redesign its residential bills as part of an overall customer education plan. Sierra Club, on the other hand, prefers an expanded bill with extensive, detailed line items and recommends rejecting the Company's bill simplification proposal. These conflicting views are illustrative of the challenges inherent in any bill redesign project. APS will be seeking customer and stakeholder input throughout the process and anticipates that, in doing so, it will receive varying perspectives. APS has engaged IBM to assist with, among other things, compiling and synthesizing these diverse perspectives and bringing them together with strong customer and industry research to develop an easily understandable and research-based bill proposal.

Q. IS APS CONTINUING TO SEEK A WAIVER OF EXISTING BILL REQUIREMENTS?

A. No. It is too early in the bill redesign process to determine if a waiver may be required. APS intends to design a new bill that will enhance the customer experience and present the information customers need in an understandable fashion. Once the bill redesign format is finalized, APS will assess whether it may be appropriate to request a waiver of any Commission rule or requirement.

VI. <u>LIMITED-INCOME PROGRAM RECOMMENDATIONS</u>

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE COMPANY'S PROPOSALS FOR LIMITED-INCOME CUSTOMERS IN ITS DIRECT TESTIMONY IN THIS CASE.

A. In direct testimony, APS recommended changes to the Company's limited-income programs in order to better serve limited-income customers with more streamlined programs and increased funding and availability. For instance, the proposal includes allowing customers to be automatically enrolled in the Energy Support Program (Rate Rider E-3) for a discount on their utility bill if they have already qualified for certain government assistance programs such as subsidized housing and the federal Low-Income Home Energy Assistance Program (LIHEAP). APS also proposed to automatically place customers who qualify for Crisis Bill Assistance on the Energy Support Program.

In addition, APS proposed to double the annual funding amount of Crisis Bill Assistance from $1.25 million to $2.5 million to make additional funds available to more customers.

Q. HAS THE COVID-19 PANDEMIC IMPACTED THE COMPANY'S APPROACH TO ITS LIMITED-INCOME PROGRAMS?

A. Yes, the pandemic has changed much about Arizonans' lifestyles and working environments, impacting the ability of customers to access assistance and creating the need for additional support throughout APS's service territory. APS has worked hard to make the Company's limited-income assistance programs accessible and easy to navigate over the course of this year as everyone adapts to these rapidly changing circumstances.

For example, in collaboration with assistance agency partners, APS improved the Crisis Bill Assistance and Energy Support Programs by:

- Moving from annual recertification to a two-year recertification process, which allows qualified customers to stay on the Energy Support Programs longer without additional paperwork and processing on their part;

- Revising the required customer consent process to accommodate partners such as Arizona DES, Wildfire, Chicanos Por La Causa, and other assistance agencies that are shifting to telephonic and online service models rather than in-person verification processes; and

- Enabling online recertification for Energy Support Programs.

APS updated aps.com to make information on both APS and external assistance programs more easily accessible and included information on energy assistance in various targeted and mass communication. In addition to the items listed above, APS has voluntarily dedicated $6.8 million in non-customer funds to provide direct bill assistance to customers impacted by the pandemic through the APS COVID-19 Customer Support Programs. As of the beginning of November 2020, APS has distributed over $4.7 million to customers and community assistance agencies, providing over 40,000 customers with much-needed help during this time.

Q. HAS APS WORKED WITH STAKEHOLDERS TO IMPLEMENT CHANGES TO SUPPORT THIS POPULATION?

A. Yes. APS worked with community assistance partners to connect limited-income customers who have struggled or are delinquent on their bills with external assistance programs by sending agency-specific emails and direct mailings to select customers. In addition, APS has worked with partners to include limited-income program assistance flyers in multiple Arizona food bank boxes.

APS also met frequently over the past several months with these partner agencies to listen to and understand the concerns and challenges they face as they work with those who have the greatest needs within Arizona communities. APS quickly made the changes noted above, finding ways to be flexible and to work together to help customers gain access to available assistance.

This collaboration on program enhancements and additional communication efforts have been successful, increasing enrollment in our Energy Support Programs by more than 25% from June 2019 (end of the Test Year in this case) through the end of September 2020.

Q. HAS APS INCREASED THE PROMOTION OF ITS LIMITED-INCOME PROGRAMS DURING THE PANDEMIC?

A. Yes. Making customers aware of the assistance programs and resources available to them during this challenging time has been a top priority for APS and the Company has significantly increased the level of marketing and customer outreach in this area. Through 2020, APS will have provided more than 75 million impressions through 13 different communication channels regarding APS's customer assistance programs. These include promotion of the Energy Support Program and Here to Help messaging that promotes APS and community partner assistance resources, energy efficiency programs and energy savings tips. Samples of APS communications are included as Attachment MW-02RB.

Q. WILDFIRE WITNESSES CYNTHIA ZWICK AND JOHN HOWAT HAVE MADE SEVERAL RECOMMENDATIONS FOR CHANGES IN APS'S LIMITED-INCOME PROGRAMS. HAVE YOU REVIEWED THOSE RECOMMENDATIONS?

A. Yes. Wildfire is recommending two categories of changes to APS's Energy Support Programs: an expansion of eligibility limits and a redesign and increase of the bill discount amounts.

Q. DOES APS AGREE WITH WILDFIRE WITNESS ZWICK'S PROPOSAL TO EXPAND THE ELIGIBILITY FOR THE ENERGY SUPPORT PROGRAMS FROM 150% TO 200% OF THE FEDERAL POVERTY LIMIT?

A. Yes. APS agrees that, especially in light of these difficult economic times, it is appropriate to expand its Energy Support Programs (Rate Riders E-3 and E-4) to include more customers and increase the income eligibility from 150% to 200% of the federal income poverty guidelines.

This expansion will complement APS's recommendation to automatically enroll recipients of Crisis Bill Assistance and LIHEAP in the Energy Support Programs, as those programs allow customers with incomes up to 200% of the federal poverty level to participate. It also will be easier to implement automatic enrollment by aligning the programs with most of the major state and federal assistance programs, further aiding efforts to collaborate across programs and agencies.

Additional funding will be required over the next several years to support the anticipated increased enrollment levels. Therefore, approval of the limited-income deferral order, proposed in APS witness Hobbick's Direct Testimony, becomes even more fundamental to the Company's ability to expand these programs to meet the needs of customers, and any expansion of the programs must be coupled with its approval.

APS is committed to continue building awareness of the Energy Support Programs and will coordinate with Wildfire and other community assistance agencies to promote the programs and enable greater customer participation. APS believes these changes will streamline the administrative burden for limited-income customers, community action agencies and APS, while providing critical assistance to Arizona's most vulnerable customers.

Q. DO ANY OF THE INTERVENORS SUPPORT THE PROPOSED LIMITED-INCOME DEFERRAL ORDER?

A. Yes. Wildfire supports the proposed deferral order.

Q. WILDFIRE WITNESS HOWAT PROPOSES AN ALTERNATIVE AND EXPANDED BILL DISCOUNT DESIGN FOR ENERGY SUPPORT PROGRAM CUSTOMERS. DO YOU AGREE WITH THAT PROPOSAL?

A. No. The Wildfire alternative discount proposal appears to contemplate a tiered bill discount for limited-income program participants that would be based on customer income, household energy burden (as determined by percentage of energy cost to total income) and the dollar amount of any account payment delinquencies. It contemplates discounts ranging from the current 25% all the way up to a 79% discount.

APS witness Hobbick will address the details of this proposal. APS understands the intent of the program, but the Company is concerned about the cost and complexity, and for these reasons does not support changing the 25% limited-income discount at this time. APS is open to exploring options to revise the program in the future to take energy burden into consideration.

Q. IN LIEU OF THIS MORE COMPLICATED DISCOUNT, WILDFIRE RECOMMENDS INCREASING THE EXISTING BILL DISCOUNT FROM 25% TO 30%. DO YOU SUPPORT THIS PROPOSAL?

A. No. The current 25% bill discount strikes an appropriate balance between those customers that need assistance and all other customers who effectively pay for that assistance.

APS offers one of the largest discounts available to limited-income customers in Arizona. The average monthly discount for Energy Support Program participants ranged from just over $22 in April 2020 to over $58 in August 2020, as the percentage-of-bill discount method provides more relief to customers during high-usage months. In contrast, other utilities in the state offer flat monthly dollar discounts ranging from $16 per month to $23 per month.

Q. WILDFIRE ALSO PROPOSES A DEBT FORGIVENESS PROGRAM. DOES THE COMPANY PLAN TO ADOPT THIS RECOMMENDATION?

A. No. APS already works collaboratively with customers to set-up and modify payment plans for past due balances. As mentioned previously, there are existing customer assistance programs available such as LIHEAP, Coronavirus Aid, Relief and Economic Security (CARES) Act funding, and other community action agency and utility bill assistance programs, along with APS programs such as Crisis Bill Assistance, the Energy Support Programs, Project Share, and the COVID-19 Customer Support Fund. I believe existing customer assistance programs, used in conjunction with APS's extended payment arrangements, are the best and most responsible way to help the most vulnerable and impacted customers address their current overdue balances.

Q. ARE THERE OTHER SOURCES OF FUNDING AVAILABLE TO CUSTOMERS WHO ARE HAVING TROUBLE PAYING THEIR BILLS?

A. Yes. There are a variety of state and federal assistance programs available to eligible APS customers, and APS works with agency partners to connect customers to these programs. From January through October of 2020, APS customers received over $5.2 million in LIHEAP, CARES Act, and charitable organization assistance, as well as approximately $4.7 million from APS-funded utility bill assistance. APS provided $23.8 million in utility bill discounts and over $2.2 million in Weatherization improvements. APS understands the needs are great, and that is why the Company is committed to continuing to support and expand partnerships and cooperation with community action agencies and charitable, state and local programs to connect our customers with available support and assistance.

VII. EDUCATION AND OUTREACH PLANS

A. *The 2016 Rate Case Customer Education and Outreach Plan*

Q. CERTAIN INTERVENORS, INCLUDING STAFF, RUCO AND WRA, HAVE EITHER CITED OR RELIED IN PART ON THE BARBARA ALEXANDER REPORT[1] (ALEXANDER REPORT) IN THEIR TESTIMONIES. HOW HAS THE COMPANY RESPONDED TO THAT REPORT?

A. APS has engaged Guidehouse Inc. (Guidehouse), a leading global provider of consulting services to the public and commercial markets with expertise in the electric utility industry, utility education and outreach best practices, and

[1] *See* Barbara R. Alexander, An Evaluation of Arizona Public Service Company's Customer Education Plan and its Implementation, Docket Nos. E-01345A-19-0236 and E-01345A-19-0003 (May 19, 2020).

behavioral science, to (1) review and analyze the Alexander Report, and (2) advise APS of improvements it should consider incorporating in future customer education and outreach initiatives. On November 2, 2020, Guidehouse issued a *Review of the 2017 Customer Education and Outreach Plan & Response to the Plan* (Guidehouse Report). Because of its foundation in appropriately compared best practices, this is the document that should serve as the basis for recommendations going forward. I have attached the Guidehouse Report to my testimony as Attachment MW-03RB and incorporate it by reference as part of my testimony.

Q. BRIEFLY, WHAT DID GUIDEHOUSE CONCLUDE REGARDING THE ALEXANDER REPORT?

A. The Guidehouse Report calls into question elements of the Alexander Report's assessments, comparisons and conclusions. Guidehouse identified crucial facts concerning the 2017 CEOP, which the Alexander Report failed to consider.

Specifically, the Guidehouse Report identified two errors and six clarifications to key points in the Alexander Report. These are discussed in detail on pp. 13-16 of the Guidehouse Report. While I will not repeat each of them here, there are a few critical issues that I want to address:

- The Alexander Report incorrectly states that existing customers who had not selected a TOU or demand rate would be involuntarily moved to one during transition. No customers were involuntarily moved to TOU or demand rates during the rate transition. Customers were moved to their Most-Like Rate during the transition (*e.g.*, only if a customer was already on a plan with a demand charge could they be defaulted to a plan with a demand charge).

- Demand rates remain entirely voluntary for APS customers.

- After completion of the rate transition period in the last rate case, customers who used 1,000 kWh or more on average per month were reassigned annually to a TOU rate consistent with Decision No. 76295. Based on feedback from customers and intervenors in this case, APS proposes to eliminate this practice and will make a non-time differentiated (*i.e.*, a flat rate) available to all customers irrespective of their usage amount.

- APS also included educational content to explain demand rates throughout the CEOP implementation. Guidehouse Report at iv-v.

Q. DOES GUIDEHOUSE PROVIDE ANY ANALYSIS OF THE ALEXANDER REPORT'S USE OF THE CALIFORNIA UTILITIES' MARKETING, EDUCATION AND OUTREACH PLAN (CALIFORNIA MEOP)?

A. Yes. Guidehouse found that there were critical structural differences between the California rate structures and transition and APS's rate structures and transition, which make the California MEOP an inappropriate and inaccurate comparator. For example, while California's rate plans were undergoing an enormous change moving from tiered untimed energy only rates to default TOU rates for all customers, whereas "…APS's CEOP was designed to help transition the vast majority of its residential customers to rates that were structurally similar to their previous rates (the Most-Like Rate)." *Id.* at 17. As a reminder, APS has had TOU and demand rates for residential customers for decades. Thus, the purpose and goals of the California MEOP were far more expansive than the purpose of the CEOP.

Guidehouse also found that the California utilities' rate transition was "meaningfully different in its size, complexity and breadth" and cost when compared against APS's rate transition, thus it was not a good comparator. *Id*. at 18. For example, Southern California Edison had an approved budget of more than $70 million for 2017-2020. In contrast, APS had an approved budget of $5 million and 9 months to implement. Given these differences in size, scope and underlying purpose, Guidehouse concluded that the Alexander Report's *ex post facto* comparison of APS's 2017 CEOP to the California utilities' MEOPs was inappropriate.

Q. HOW DO YOU RESPOND TO THE INTERVENORS WHO CHARACTERIZE THE CEOP AS A "FAILURE?"

A. As is often the case, hindsight provides a clear view into things that could have been done differently and/or better. But I disagree with the harsh characterization of the CEOP as a "failure." Guidehouse assessed the CEOP and compared it to industry norms, and they concluded that the CEOP met and, in some instances, exceeded industry norms. Guidehouse also found that APS's use of a wide range of traditional and digital marketing, its community-based outreach, and use of engaging customer materials and tools met the standards for best practices in the industry. This portion of Guidehouse's assessment can be found on pp. 39-42 of their report. The *Rate Review and Customer Outreach Program Evaluation of Arizona Public Service Company*[2] that was conducted by Staff consultant Overland Consulting likewise found that much of the CEOP was reasonable and appropriate. While I agree that there are areas that the Company can look to improve going forward, the harsh rhetoric surrounding the 2017 CEOP is not supported by the facts.

[2] *See* Overland Consulting, Rate Review and Customer Outreach Program Evaluation of Arizona Public Service Company, Docket No. E-01345A-19-0003 (June 4, 2019).

Q. WHAT IS APS CURRENTLY DOING TO IMPROVE ITS CUSTOMER EDUCATION AND OUTREACH?

A. APS holds regular Customer Advisory Board and stakeholder meetings, covering topics ranging from the disconnect moratorium to rate design and education. These serve as vehicles for gathering valuable insights. The Customer Advisory Board was launched in May 2020 and is comprised of approximately 30 customers who are diverse in geographic location, demographics (age, gender, income, ethnicity), APS sentiment, and service plans.

By the Order of the Commission, APS implemented pro forma billing in March of 2020 that provides customers with on-bill rate plan analysis each month to see their lowest cost plan, current month savings, and cumulative 12-month savings. This regular reminder of such valuable information has led to an immediate increase in customers changing rate selections. APS is also focusing its customer communications on topics that align with JD Power learnings including assistance, billing and payment programs, and energy efficiency.

B. *APS's Plans for Future CEOPs*

Q. WHAT IS APS'S PLAN FOR ITS CUSTOMER EDUCATION AND OUTREACH IN THE FUTURE?

A. Looking ahead, APS is focused on continuously improving customer communications and the customer experience. While the primary focus of the new CEOP is customer awareness and understanding of the available rate plan options, it will also outline other related customer programs to create a coordinated and holistic approach to customer outreach and education. The CEOP is an integral component of the customer experience and will continue to be an ongoing part of APS's business operations, not just a one-time plan. APS plans to incorporate many of the learnings from the 2017 CEOP as well as best practices recommended by Guidehouse and others. Key elements of the CEOP will include an overview of objectives, related research and key learnings, limited-income program, messaging strategy, communication tactics, call center training and a performance measurement plan. APS intends to provide a new CEOP that is informed by the Commission decision in this case, which encompasses the items discussed below.

Q. WHAT WILL THE NEW CEOP ADDRESS?

A. The Company has heard customers, stakeholders and Commissioners. As I stated above, customers are at the heart of everything APS does. The Company's new CEOP will be designed with the customers in mind and will take a robust approach to addressing their needs and concerns. The new CEOP will consider:

- Customer and Stakeholder Feedback – APS will seek the Voice of the Customer through various customer research approaches and will engage external stakeholders through a structured process to solicit recommendations and input throughout the CEOP development process.

- Industry best practices – APS will engage external consulting resources with utility industry knowledge and experience, as well as communication and marketing subject matter expertise, in the development of the CEOP.

- Rate plan lifecycle approach – The CEOP will go beyond the initial customer education and awareness phase that enables a customer to make an informed rate plan choice that meets individual needs and preferences – whether that be a focus on cost, convenience, or other considerations. The CEOP will also address how to help customers optimize their selected plans over time through plan-centric energy tips, reminders about energy efficiency program options and energy usage alerts.

- Behavioral science – Research in this area indicates that most people tend to stay with the status quo or default option when faced with a decision. Behavioral science indicates that for those people who do make an active choice, a wide range of non-economic factors are likely to influence the decision-making process. As a result, both economic and non-economic factors should be integrated into the tools and materials used to inform customers about their rate choices. By addressing other customer motivators as well as the most economical plan (MEP), customers will be able to make a more informed choice and have a better experience.

- Integration – The CEOP will address how to integrate related customer programs to create a holistic, customer-centric outreach plan. Examples of programs to be integrated into the CEOP include limited-income assistance programs, energy efficiency program offerings, energy usage alerts, and billing and payment programs such as Budget Billing that assist customers with affordability and provide convenience.

- Cross-channel integration – The CEOP will ensure consistency of rate and program information and presentation across various customer touch points: Care Center, aps.com, billing, rate comparison tool, promotional materials, emails, digital communication, etc.

- Simplicity – A key objective of the CEOP will be to simplify the presentation of rate plan and program offerings for customers. This will include the use of visuals and infographics. Messages and content will be pre-tested with customers.

- Broad and Targeted Customer Outreach – The CEOP will be designed to achieve broad awareness of offerings, options and programs that factor into overall customer satisfaction while targeting customer communications that reflect a personalized preference or a call to action specific to a customer or customer segment.

- Customer Segmentation – The CEOP will identify and address the unique needs and perspectives of customers through a thoughtful approach to customer segmentation. Customer segments that will be addressed include limited-income customers, customers who prefer Spanish language communications and other unique customer segments. The intent of this customer segmentation is to improve the effectiveness of education and outreach by better understanding and addressing customers' needs, preferences and challenges and how best to reach each segment.

- Performance Measurement – The CEOP will include a performance evaluation plan that documents and evaluates the performance of program-related initiatives. Performance evaluation will be used to inform changes to program efforts and materials in an ongoing cycle of continuous process improvement.

Q. DO YOU HAVE A DIGITAL ENGAGEMENT FOCUS AS PART OF YOUR FUTURE EDUCATION AND OUTREACH PLANS?

A. Yes. Digital engagement is a significant driver of customer satisfaction. APS will seek customer input, adopt best practices, and focus on providing or enhancing the most important digital transactions.

One example of digital engagement is our work on an Energy Estimator Tool that will be available to residential customers on aps.com in the first quarter of 2021. This tool, which is in the development stage, will help customers understand their demand impacts of running single appliances or multiple appliances together during peak hours, and how changes in appliance use can impact the amount and cost of their usage or demand. The tool also will allow customers to select different configurations of home sizes, seasons and rate plans. As previously noted, this tool is based on customer research and includes stakeholder input.

VIII. <u>SUBSCRIPTION RATE PILOT PROGRAM</u>

Q. IN LIGHT OF THE INTERVENOR TESTIMONY LARGELY RECOMMENDING THAT THE COMPANY'S PROPOSED SUBSCRIPTION RATE PILOT PROGRAM BE REJECTED, DOES APS PLAN TO PURSUE THE SUBSCRIPTION RATE?

A. No. APS is withdrawing the subscription rate option from our overall rate plan proposal. In the future, APS will do additional customer research and work with customers and stakeholders to discuss the program purpose and design. Currently, however, APS's immediate focus is on simplifying our core rate plan portfolio, enhancing our CEOP and including the integration of customer programs to deliver a great customer experience and value, with a particular emphasis on our limited-income customers.

IX. <u>CUSTOMER SERVICE REPORTING RECOMMENDATIONS</u>

Q. DID YOU REVIEW THE PROPOSED CUSTOMER SERVICE REPORTING REQUIREMENTS, AND DO YOU HAVE ANY GENERAL COMMENTS?

A. Yes. APS witness Barbara Lockwood explains APS's overall proposed reporting strategy. An appropriate set of reporting requirements should provide meaningful insight into APS's customer service and help track the Company's performance over time. For that reason, I do not support several of the recommendations made by intervenors as they are too detailed and specific to very narrow issues. Additionally, while APS is aggressively pursuing improvements in customer service, prescriptive targets can have unintended consequences and lead to negative incentives, undermining agility as customer expectations and best practices evolve over time. As APS continues to improve its customer service, the Company must also maintain flexibility in its approach and methods. Tying customer service too stringently to any specific metric can hamper overall progress. Before I get to my recommendations, I would like to clear up some comments made about APS's customer service metrics.

Q. HAVE YOU REVIEWED RUCO'S DIRECT TESTIMONY REGARDING J.D. POWER?

A. Yes. RUCO's claims regarding the Company's use of J.D. Power are incorrect. I address these claims below.

Q. DID THE COMPANY STOP USING J.D. POWER AFTER THE 2016 RATE CASE?

A. No. The Company continued to subscribe to the J.D. Power Electric Residential Customer Satisfaction study from 2017 to 2020 and analyzed and reported its results on a quarterly basis to Officers, Customer Service and Communications. In 2017, APS transitioned the metric used for determining incentive compensation from J.D. Power to a different customer satisfaction metric called the Customer Contact Tracker (CCT). It is common practice for utilities to adjust their customer satisfaction measurements, shifting between various syndicated studies, transactional surveys, or proprietary studies depending on the specific needs of the company.

CCT is different from J.D. Power in that CCT surveys a customer about his or her experience about specific types of recent transactions with the Company, such as when a customer calls our Care Center, whereas J.D. Power surveys customers randomly, irrespective of whether they have had a recent interaction with the Company. The shift to CCT was timed with the Company's conversion to a new billing system in order to address any challenges in phone service levels and billing during the migration. CCT enabled APS to monitor performance during this transition using near-real-time data (vs. quarterly data with J.D. Power) to serve as a leading indicator for performance and measurement improvement.

APS switched to CCT to monitor and respond to customers during this major transition, not to circumvent declining satisfaction results as RUCO alleged. As RUCO acknowledged in its testimony, APS shifted to CCT to provide greater insight into the customer experience following a specific customer interaction with APS, and the Company continues to use CCT today given its usefulness as a transaction study.

Going forward, APS will be using the J.D. Power overall satisfaction ranking as a company-wide incentive metric to take a more holistic approach to analyzing and addressing overall customer satisfaction. The Company will continue to track transactional performance through transactional studies similar to CCT. These types of tools remain useful in making year-to-year improvements and monitoring performance through specific transactions and channels.

Q. WHAT DO YOU RECOMMEND FOR REPORTING REQUIREMENTS?

A. The table below lists my recommended reporting requirements and their frequency. These items were generally supported by Staff, Sierra Club and RUCO.

Figure 2

Proposed Customer Service Reporting and Frequency

Category	Description	Frequency
Rate Selection	Residential customer rate plan distribution	Quarterly; until the next rate case
	Number of customers on MEP	Quarterly; until the next rate case
Care Center Performance	Percent of service calls answered within 30 seconds	Quarterly
Customer Satisfaction	JD Power customer satisfaction rankings	Quarterly
Customer Complaints	ACC complaints	Quarterly

Q. PLEASE ELABORATE ON THE RECOMMENDATIONS ABOVE.

A. Each of the items in the table are discussed below.

A. *Rate Selection*

Preserving customer choice is an important part of APS's rate plans, as is providing the correct education to help customers understand their rate options. Tracking metrics like these gives one view into how effective that education is, as well as how other mechanics of APS's rates are operating. As APS embarks on a new education plan, and while the rate plans are newer, quarterly reporting is appropriate. APS believes that reporting on these items until the next rate case will provide sufficient time to analyze how customers continue to move between rates.

B. *Care Center Performance*

The Care Center is an integral part of APS's relationship with customers. How quickly representatives respond to customer calls is one indicator of how efficiently the call center is performing. While APS tracks Care Center performance on a daily basis, due to known seasonal variations, I recommend quarterly reporting for these statistics. A telephone service level, measured in the percentage of calls answered in 30 seconds or less, is a universal and best practice call centers measure across the industry. It is worth noting that answering 80% of calls in 30 seconds or less is best-in-class performance, and many utilities perform below this threshold.

C. *Customer Satisfaction*

Customer satisfaction is a top priority for APS. As such, the Company will focus reporting efforts to measure overall customer satisfaction. APS uses J.D. Power's nationally syndicated Electric Residential customer satisfaction survey. To perform well in J.D. Power's overall customer satisfaction, a utility must perform in six key drivers of customer satisfaction and 40+ attributes. Results are reported as a ranking compared to other utilities.

D. *ACC Complaints*

Customer feedback is foundational to customer satisfaction and the Company's ongoing improvement efforts to enhance customer experiences. Therefore, I support quarterly reporting of ACC complaints.

Q. CERTAIN INTERVENORS CONTEND THAT ACC COMPLAINTS ABOUT APS HAVE BEEN TRENDING UPWARD IN 2019 AND 2020. CAN YOU ADDRESS THE NUMBER OF COMPLAINTS THE COMPANY IS EXPERIENCING AND ANY CURRENT TRENDS?

A. The total number of ACC customer complaints are decreasing when compared year-over-year. The data below show an increase in ACC customer complaints after the 2016 rate case, which peaked in 2018. The most impactful changes from a customer complaint standpoint were related to the new billing system conversion, new rates and the rate migration. The downward trend identified in 2019 and 2020 is a reflection of stabilizing the new customer billing system, and customers acclimating to both new rates and prices from the August 2017 rate settlement, along with significant improvements in our Care Center performance. Since 2017, the Company has seen year-over-year improvement in service levels for residential and business customers. As of the end of October 2020, Care Center advisors are answering 74% of calls in 30 seconds compared to 43% in 2017.

Figure 3

Annual ACC Customer Complaints

Year	Customer Complaints (ACC)
2016	533
2017	958
2018	1109
2019	505
2020	283[3]

Q. STAFF RECOMMENDED REPORTING ON KEY CREDIT AND COLLECTION METRICS. WHY ARE THOSE NOT IN YOUR RECOMMENDATION?

A. I agree with Staff that disconnects, payment arrangements and similar items are extremely important to track and provide transparency. However, APS already reports on these items in a number of places. Additionally, the Commission currently has a rulemaking docket (Docket No. RU-00000A-19-0132) open where the Commission will likely decide issues such as reporting these and

[3] Through September 2020.

similar topics for all jurisdictional utilities in the state. It is more appropriate to determine these kinds of reporting requirements in a generic proceeding.

X. CONCLUSION

Q. DO YOU HAVE ANY CLOSING COMMENTS?

A. APS's mission is to provide customers with clean, reliable and affordable energy. This commitment to customers is at APS's core. With customers at the center, APS will deliver an industry-leading customer experience and improve customer satisfaction. APS will accomplish this through items noted in my testimony and prioritizing what matters most to our customers in the areas of reliability, value for price, billing and payment experience, community and environmental stewardship, customer communication, and customer care, including customers' digital and phone experience. APS is committed to moving forward and continuing to collaborate with customers and stakeholders as the Company provides the essential and important service they rely on to power their homes, schools, and businesses.

Monica Whiting

Customer Experience, Communication & Utility C-Level executive with a passion for leading teams to achieve best-in-class results. Unique balance in delivering results while inspiring the hearts and minds of people; setting clear direction through long-term strategic focus & short-term tactical plans. Proven track record in leading change, delivering high customer and employee satisfaction coupled with cost-effective operations.

SUMMARY OF QUALIFICATIONS

- 25-plus years multi-service utility experience – electric, natural gas, water & sewer
- 15 plus years leadership experience including C-Level leadership
- Proven track record in leading diverse teams through a customer transformation while improving employee engagement and cost efficiency
- Successful deployment and leveraging of technology, process improvements and infrastructure maintenance to reduce manual operations, improve customer service delivery and reduce operating costs.
- 2012 KITE Customer Service Leader of the Year
- Frequent national speaker & panelist – Customer Experience, Employee Engagement, Strategic Planning

PROFESSIONAL EXPERIENCE

APS – Arizona Public Service, Phoenix AZ **July 2020 - present**
Vice President, Customer Experience

TECO -- Tampa Electric Company (TEC) & Peoples Gas System (PGS), Tampa, FL Jan 2017 - July 2020
Vice President, Customer Experience

- Member of TECO's Executive Leadership & Officer team serving TEC's & PGS's 1.2 million plus customers, $2.5 billion in revenue and annual budget of $65 million plus
- Leader of approximately 470 union and professional employees
- Responsible for TECO's Customer Strategy & Transformation, including Customer Revenue, Strategic Customer Accounts, New Construction, Customer Experience Centers, Customer Solutions & Digital Customer Experience, Energy Efficiency & Renewable Programs, Customer Systems Administration, Corporate Communication & Marketing, Customer Strategy, Voice of the Customer Program, Compliance & Continuous Improvement.
- Key Accomplishments in three years Include:
    - Successful implementation and stabilization of new customer billing system
    - Integration and management of 80 plus systems & business processes that deliver Customer Experience
    - Deployment of company's first digital strategy
        - 62% plus active customer accounts
        - Ranked in 1st quartile nationally for mobile experience and 2nd quartile nationally overall digital experience in JD Power's 2019 Digital Study
        - 48% customers on electronic billing
        - 72% of customers pay electronically
    - Transformation of customer operations since 2016 including:
        - 17% reduction in call volume
        - 72% improvement in service level
        - 87% improvement in abandonment rate
        - 14% improvement in average handle time
        - 91% improvement in average speed of answer
        - 6% reduction in operating costs
        - 50% plus reduction in billing exceptions and estimated bills
        - 99% plus or greater of bills produced accurately and timely
        - 25% FTE reduction

TECO Continued –

- Developed & Implemented corporate customer experience strategy
  - Tampa Electric -- Year-over-year JD Power improvement for residential and business customers achieving company's highest scores and improved Net Promoter Scores
    - Improved 98 points in residential study moving from ranking of 101 to 46 nationally
    - Named among most improved utilities from 2017 – 2019
    - Improved 102 points in business study moving from ranking of 57 to 18
    - Improved Net Promoter Scores by 12 points for Residential and 15 points for Business
    - Named by Escalent as 2019 Trusted Business Partner
  - Peoples Gas – Improved already industry leading scores ranking top 3 in the nation
    - Earned Highest in Residential Customer Satisfaction among Midsize Natural Gas Utilities in the South, 7 years in a row;
    - Earned Highest in Business Customer Satisfaction in the South Segment for the 3rd time.
    - Named by Cogent/Escalent: 2019 Most Trusted Brand & Customer Engagement for the 5th time; also named Customer & Environmental Champion for the sixth consecutive year; 2019 Easiest Utility to Do Business With
- Key contributor to successful corporate revenue & financial success through
  - Economic Vitality & Retention contracts
  - Industry leading write-off and aged-receivable management
  - Reductions in operating expenses while improving service levels and employee engagement
  - Revenue generation through fraud management, revenue generating products and services
- Member of Unified Command for Hurricane and Pandemic Response
- Customer Experience team accomplished more than 1 million hours worked with zero recordables
- Customer Experience employees ranked high in Employee Engagement scores compared to industry benchmarks

JEA, Jacksonville, FL April 2013 – Dec 2016

Chief Customer Officer

- Leader of 460 plus union, appointed and contract employees plus contracted services
- Responsible for delivering nationally-recognized customer experience to nearly 1 million electric, water & sewer customers
- More than $2 billion in annual customer billings and collections with less than 0.20% write-offs
- Operating budget of ~ $80 million annually – capital and o&m
- Functional responsibilities include Customer Billing, Revenue Collections, Key Account Management, Customer Experience Centers, Data Analytics, Customer Systems Administration, Customer Solutions Development & Management, Community Engagement, Corporate Communications & Strategic Marketing including Digital Media & Services, SmartGrid, Demand-Side Management & Renewable Programs and Field & Meter Services Operations.
- Active member of Senior Leadership Team working in partnership with CEO, CFO, CHO & Operating Chiefs, as well as Board of Directors

Key Accomplishments include:

- Led organization through customer-centric & employee engagement culture transformation using Accelerated Corporate Transformation strategic planning model
  - Led JEA transformation from worst to first in JD Power Customer Satisfaction in 3 years
  - Most improved utility nationally (2010 – 2015) & (2011 – 2016)
  - #1 in Business South Mid-Size Segment and in Florida – 2016
  - #1 in every business driver in South Mid-Size Segment and top quartile nationally – 2016
  - Moved from 4th quartile – 1st quartile in less than 3 years for both residential & business – 2012 – 2015
- 1st quartile in customer service operating costs nationally – 12% reduction
- Improved employee satisfaction & engagement, including union relationships
- 40% improvement of safety recordable incident rate
- Transformed Customer Experience technology reliability & functionality to best-in-class website & IVR, handling 78% of transactions, earning best-in-class distinction by JD Power and other industry benchmarks
- Executive Sponsor of successful implementations and upgrades of several key Customer Experience technologies including billing system, outage management system, meter data management, e-payments, etc.
- Improved Account Management Practices from 3rd Quartile to Best in Class – E Source
- Recovery of more than $5 million of unbilled revenue in two years, through improved infrastructure maintenance, data analytics, process improvements and employee training
- Delivered organization's best customer experience during Hurricane Hermine and Matthew Restoration Response
  - 85-90% outage reporting & communication through web, IVR and text
  - Phone calls answered in less than 60 second Average Speed of Answer
  - Increased Social Media, Outage Map and Notification Volume 60 – 100 times normal

Colorado Springs Utilities, Colorado Springs, CO — August 1999 – March 2013 & Feb. 1994 – April 1997
Customer Revenue & Service Department General Manager *(April 2008 – March 2013)*
Customer Service Department Manager *(April 2004 – April 2008)*

- Lead up to 170 exempt & non-exempt employees plus vendor contracts
- Responsible for delivering nationally recognized customer service to more than 250,000 combined electric, natural gas, water & wastewater customers.
- Billing & revenue collection of more than $850 million annually
- $15 million plus annual operating budget
- Functional areas include Customer Billing, Customer Collections & Payment, Strategic Account Management, Economic Development, Product & Service Development and Delivery, Business System Analysts and Customer Service Center.

Key Accomplishments include:

- Annual top quartile JD Power rankings in Customer Satisfaction – Residential & Business
- Improved operating efficiencies 9% - 30% annually bringing operating costs within benchmarks
    - $1.5 million in savings and 10% labor reductions through employee-led continuous improvement efforts, automation and metric management
- Development & execution of new corporate Economic Vitality Strategy in partnership with City & EDC, enhancing community relationships & reputation, developing portfolio tools include new rate options & special contracts, helping retain and acquire new jobs
- Development of strong safety culture with employee accountability
- Emergency Response to weather-related events and Waldo Canyon Fire
- Development of Water Conservation & Drought Plans including Xeriscape Education, Conservation Rates, Watering Restrictions & Enforcement, Education and new Wastewater Rates

Market Development Manager *(October 2003 – April 2004)*
Residential & Business Market Manager *(July 2003 – October 2003)*
Residential Market Manager *(July 2001 – July 2003)*
Product Manager *(August 1999 – July 2001)*

- Led various senior professional staff and cross-divisional project teams in the development & management of a robust portfolio of Products & Services
- Built organization's Product Development and Management Program for Energy and Water Demand Side Management (DSM), Revenue Generating Customer Solutions and Customer Assistance Programs
- Developed Electric DSM strategic plan yielding commodity use reductions to meet RPS & Reduction Goals
- Directed organization's community-wide Water Saver project saving more than 6 million gallons of annual water savings in 2003 drought
- $1.7 million in non-regulated net revenue & $2 million in regulated revenue
- Expanded Customer Solution portfolio from three offerings to more than 50 customer solutions to generate non-regulated revenue, increase customer assistance support and customer satisfaction:
- Developed organization's business planning and financial analysis tools and processes for products and services, ensuring positive return on investments

Marketing Program Coordinator *January 1997 - April 1997/April – August 1997 (consultant)*
City of Colorado Springs & Colorado Springs Utilities, Colorado Springs CO *February 1994 – January 1997*
Public Communications Specialist II/Public Communications

Anaheim Public Utilities, Anaheim, CA_ — September 1997 – July 1999
Project Manager/Strategic Marketing Manager

Compassion International, Colorado Springs, Colorado — July 1992 -February 1994
Special Events Coordinator & Public Information Manager

Pasadena Tournament of Roses Association, Pasadena, California — July 1991 - July 1992
Public Relations Assistant

EDUCATION

University of Southern California, Los Angeles, California — May 1991
Bachelor of Arts in Public Relations/Journalism

COMMUNITY & INDUSTRY BOARDS & COMMITTEES

Current

• J.D. Power Executive Council • AEIC Customer Service Executive Committee Vice Chair • CS Week Executive Committee Member. • EEI Customer Centricity Committee Member.

Past

Board Member American Red Cross (Central Florida/Tampa Region) • 2013 – 2016 Board Member Leadership Jacksonville (Alumni Relations & Collegiate Leadership Experience Chair) • 2015-2016 Board Member North Florida Region Red Cross • 2014-2015 NE Florida United Way Campaign Cabinet • 2013 & 2014 Chair of LPPC Customer Service Executive Committee • 2012-2017 Knowledge Customer Service Advisory Planning Committee Oracle Customer Service Executive Committee • NE Florida United Way Leader in Giving • Colorado Springs Technology Incubator Board Member/Marketing and Metric Sub-team Chair • Colorado Springs Regional Sustainability Planning Committee & Economic Development Sub-Team • Regional AWWA Customer Relationship Board Communications Chair • Board Member of Child Nursery Centers • Governor Appointment to Colorado's Low Income Energy Assistance Commission (completed 2nd Term) • Past Community (Colorado Springs) Economic Development Steering Committee Member.

Sample of APS Customer Communications

Sample Communication 1:

Here to Help bill inserts were included in bills to all customers from October 2, 2020 to November 2, 2020. Bill inserts were sent to customers in both English and Spanish based on the customer's selected preference

Front- English

Back- English

We are holding disconnections through the end of the year, and COVID-19 relief is still available.

In the midst of a pandemic and a summer with record-breaking heat, we understand some customers are experiencing financial difficulties. Therefore, we have pledged $6.8 million in assistance for customers struggling due to COVID-19. We also stopped disconnections for non-payment, as well as late fees, in mid-March. We continued this through the summer months, and we are extending it until the end of 2020.

We hope this gives customers who are struggling to pay their bills additional time to seek available customer assistance, make partial payments and set up payment arrangements. Our assistance programs can reduce your monthly payment or help pay down the bill. Learn more at aps.com/assistance.

We are here for you 24 hours a day, 7 days a week, so please give us a call at (602) 371-7607 (metro Phoenix) or (800) 253-9409 (other areas).

LV2010006

Money-saving tips and tools to help lower your bill:

- **Service Plan Savings Tips**—Find ways to save on your plan
- **Plan Comparison Tool**—Find the plan that's best for you
- **Energy Analyzer Survey**—Get customized money-saving tips
- **Usage Alerts**—Track your monthly energy usage

Visit aps.com/save for more tips.

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Sample Communication 1 (continued):

Here to Help bill inserts were included in bills to all customers from October 2, 2020 to November 2, 2020. Bill inserts were sent to customers in both English and Spanish based on the customer's selected preference

Front- Spanish

Back- Spanish

Hemos suspendido todas las desconexiones por el resto del año y tenemos asistencia disponible para los clientes afectados por COVID-19.

En medio de la pandemia y el calor récord, entendemos que algunos clientes están experimentando dificultades financieras. Queremos ofrecer un poco de alivio. Nos comprometimos a dar $6.8 millones en asistencia para los clientes que están atravesando por dificultades debido al COVID-19. También, desde mediados de marzo, suspendimos las desconexiones por falta de pago, así como los recargos por pagos atrasados. Continuamos estas medidas durante los meses de verano, y acabamos de anunciar que las extendemos hasta el fin de 2020.

Esperamos que estas medidas proporcionen a los clientes con dificultades para pagar sus recibos más tiempo para buscar asistencia disponible, hacer pagos parciales y arreglos de pago. Nuestros programas de asistencia pueden reducir tu pago mensual o ayudarte a pagar un recibo. Aprende más en aps.com/asistencia.

Estamos disponibles para ayudarte las 24 horas del día, los 7 días de la semana, así que llámanos al (602) 371-7607 (metro Phoenix) o al (800) 253-9409 (otras áreas).

LV2010007

Consejos de ahorro y herramientas para reducir tu recibo:

- **Ahorros de planes de servicio**—Encuentra maneras de ahorrar en tu plan
- **Herramienta de comparación de planes**—Encuentra el mejor plan para ti
- **Encuesta *Energy Analyzer***—Recibe consejos de ahorro personalizados
- **Alertas de uso**—Monitorea tu uso mensual de energía

Visita aps.com/save para más consejos.

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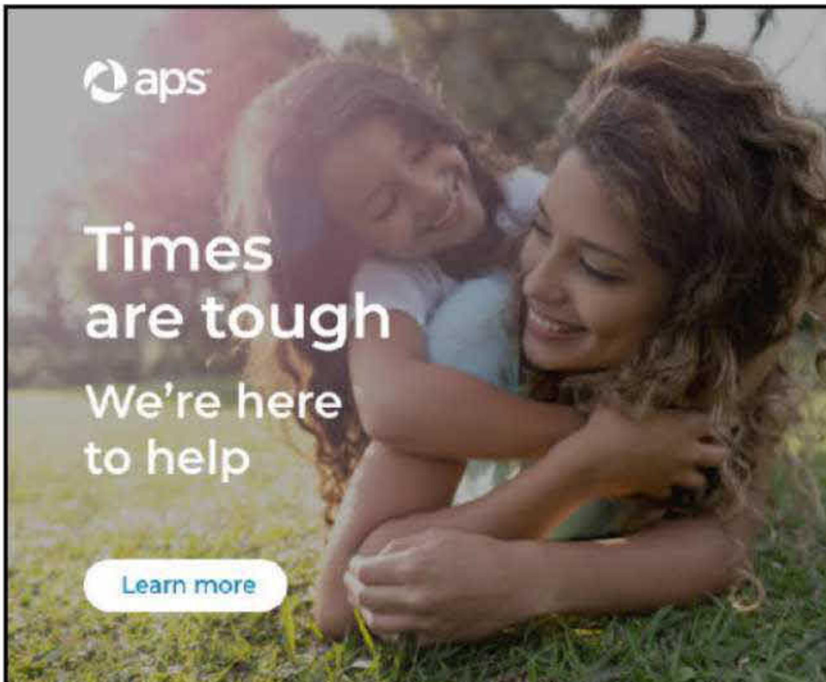
Sample Communication 2:

Print ads were run in several newspapers throughout October into early November. There were several versions of the ad, and a sample is included below.

Sample Communication 3:
Here to Help emails were sent to customers on September 15, 2020 (English) and September 21, 2020 (Spanish). Emails were sent to customers in both English and Spanish based on the customer's selected preference

Part 1:



We are holding disconnections through the end of the year, and COVID relief is still available.

In the midst of a pandemic and a summer with record-breaking heat, we understand some customers are experiencing financial difficulties. We want to provide some relief. We have pledged $6.8 million in assistance for customers struggling due to COVID. We also stopped disconnections for non-payment, as well as late fees, in mid-March. We continued this through the summer months, and we just announced we are extending it until the end of the year.

We understand how important it is to help our customers get back on their feet during this difficult time. We hope this gives customers who are struggling to pay their bills additional time to seek available customer assistance, make partial payments and set up payment extensions. We are here to partner with and help our customers.

Sample Communication 3 (continued):

Here to Help emails were sent to customers on September 15, 2020 (English) and September 21, 2020 (Spanish). Emails were sent to customers in both English and Spanish based on the customer's selected preference

Part 2:

Find help for you or someone you know.

A little help can make a big difference. We have programs and local non-profit resources for customers who need help paying their bill. Here are just some of our assistance programs that can reduce your monthly payment or help pay down the bill.

- **Crisis Bill Assistance** can provide up to $800 a year to cover APS bills.
- **Energy Support program** offers 25% off monthly bills.
- **Project SHARE** provides up to $300 in temporary bill assistance through The Salvation Army.
- **Low Income Home Energy Assistance Program** (LIHEAP) is government assistance for heating and cooling bills.

Learn more about our assistance programs and see if you qualify at **aps.com/assistance**.

Money-saving tips and tools to help lower your bill:

- **Service Plan Savings Tips**—Find ways to save on your plan
- **Plan Comparison Tool**—Find the plan that's best for you
- **Energy Analyzer Survey**—Get customized money-saving tips
- **Usage Alerts**—Track your monthly energy usage

Visit **aps.com/save** for more tips.

We are here for you 24 hours a day, 7 days a week, so please give us a call at (602) 371-7607 (metro Phoenix) or (800) 253-9409 (other areas) or visit us at aps.com/support.

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This email was sent to stefanie.becker@aps.com because you are subscribed to receive messages from APS.

Please DO NOT REPLY to this email address. This mailbox is not monitored.

unsubscribe terms of use privacy policy

aps.com

Guidehouse

Review of the 2017 Customer Education and Outreach Plan & Response to the Plan

Prepared for:

Arizona Public Service Company

Submitted by:

Guidehouse Inc.

November 2, 2020

guidehouse.com

Table of Contents

Executive Summary

Arizona Public Service Company (APS) engaged Guidehouse Inc. (Guidehouse) to provide an objective review of the APS 2017 Customer Education and Outreach Plan (CEOP) developed for the rate transition approved in the 2016 rate case and to assess subsequent responses to the CEOP, with particular focus on the report *An Evaluation of Arizona Public Service Company's Customer Education Plan and its Implementation* by Barbara Alexander Consulting LLC (Alexander Report). As part of this review, Guidehouse identified important context around customer education and outreach best practices and customer behavior related to the rollout of new rate plans, conducted a high-level evaluation of APS's 2017 CEOP from this perspective, and made recommendations for future customer education and outreach efforts related to rates.

From this review, Guidehouse identified two corrections and six clarifications to key points in the Alexander Report that are relevant to and missing from the current narrative around the 2017 CEOP and its implementation. Guidehouse also found that, overall, the Alexander Report's comparison between the CEOP and "best practices" from the California marketing, education and outreach plans has several critical flaws, particularly as an *ex post facto* (retrospective) evaluation. Guidehouse then broadened the lens of best practices into five comprehensive areas and found that the 2017 CEOP and its implementation performed at the "industry norm" level in three areas and at the best practice level in two areas. From a behavioral science perspective, APS's 2017 CEOP and its implementation were successful at integrating four important behavioral best practices into outreach and education efforts. Guidehouse also identified four areas in which APS could use behavioral science insights to improve a future CEOP and included these concepts in our recommendations.

Issue Overview

On August 18, 2017, the ACC approved the APS 2016 Rate Case under a Settlement Agreement in Decision No. 76295,[1] including both a rate increase and new rate plans. This decision also required APS to file a CEOP to educate customers about their new residential rate plan options. Essentially, the new rate plans were revisions of existing rate plans, with several modifications to better align rates with costs. The new rate plans did not represent fundamental structural changes to APS's residential rate design (e.g., a change from flat or tiered rates to time-based rates), unless customers voluntarily selected such a change. The customer "rate transition" involved the following key actions:

- Instituting a rate increase, per the outcome determined in Decision No. 76295.
- Instituting new time-of-use (TOU) periods and other modifications (summer/winter differential changes, fewer on-peak hours, and more off-peak holidays), per the outcome determined in Decision No. 76295.
- Informing and educating customers to enable them to select their preferred rate plan.
- Defaulting customers to their "Most-Like Rate" from February 1 to May 1, 2018, if they did not select an alternative prior to the automatic transition period. The Most-Like Rate

[1] Arizona Corporation Commission, Decision No. 76295, August 18, 2017, https://docket.images.azcc.gov/0000182160.pdf.

default was approved as part of Decision No. 76295 and agreed to by the settling parties.

The development of the CEOP and collection of formal stakeholder feedback both took place through a short three-step process defined in Decision No. 76295: 15 business days for APS to file the draft CEOP, 10 days for stakeholders to file comments, and 10 days for APS to file the final plan.

Guidehouse notes that the final CEOP filed September 29, 2017 is a 12-page document that provided a written overview of APS's plan. It is a relatively high-level summary that was finalized on a short timeframe, and as such did not include details on the many separate and specific education and outreach activities APS undertook over the course of the entire rate transition timeline.

APS moved forward with its rate transition-focused outreach and education activities from October 2017 to May 2018, and the automatic rate transition for customers who had not selected a new plan began February 1, 2018 and was completed by May 1, 2018, as approved in Decision No. 76295. However, on January 9, 2019, the ACC directed the Utilities Division Staff to conduct a review of the effectiveness of APS's CEOP and to initiate a rate review of APS's current rates (APS 2019 Rate Review).[2]

In Decision No. 77270 on June 27, 2019,[3] the ACC directed Commission Staff to "select and hire an independent consultant, paid for by APS, to develop a program to properly and adequately educate customers on all aspects of APS's rate plans." Commission Staff hired Barbara Alexander Consulting LLC, which resulted in the Alexander Report published recently on May 19, 2020. However, this report did not develop the program on APS's behalf and focused instead on evaluating the 2017 CEOP.[4]

Review of the Alexander Report

Guidehouse closely reviewed the Alexander Report in two major areas: (1) key findings regarding the 2017 CEOP and its implementation and (2) the basic premise of the Alexander Report, which is that the ME&O plans developed by the California investor-owned utilities (IOUs) should serve as the basis for comparing APS's CEOP to best practice. The objectives of this review were to determine if the Alexander Report had accurately characterized what occurred leading up to and during the rate transition process, and if there were any flaws with the comparison of APS's CEOP to California's default TOU ME&O campaign and whether this was an appropriate comparison.

Alexander Report Corrections and Clarifications

Guidehouse identified two corrections and six clarifications to key findings in the Alexander Report that are relevant to and missing from the current narrative around the 2017 CEOP and

[2] Docket No. E-01345A-19-0003.

[3] Arizona Corporation Commission, Decision No. 77270, June 27, 2019, Docket No. E-01345A-19-0003, https://docket.images.azcc.gov/0000198805.pdf.

[4] "While this Report identifies the shortcomings of APS's Customer Education Plan, it is not my recommendation that the Commission or the Commission Staff should develop a customer education plan or implement customer education on behalf of APS." Page 7, *An Evaluation of Arizona Public Service Company's Customer Education Plan and its Implementation*, Barbara Alexander Consulting LLC, May 19, 2020.

its implementation. The statements selected for inclusion in the following table were taken from the Alexander Report executive summary, in order of appearance, and are intended to be illustrative of key concepts described in that report. A more detailed version of this table may be found in Chapter 2.1.

Table 1. Identification of Issues in the Alexander Report

#	Issue Type	Reference	Guidehouse Comments
1	Clarification	"…most of the comments from consumer organizations were ignored in the final version of the Plan." (p. 2)	• APS met with the stakeholder group and adopted three of the nine comments on a short timeframe. APS appears to have later addressed the substance of five other comments.
2	Correction	"…it was assumed that the vast majority of customers who had not voluntarily selected a time of use or demand charge plan in the past would be moved to a time of use or demand side for the first time." (p. 2)	• Customers were not involuntarily moved to demand rates either during the rate transition or during the annual rate reassignment process.[5] • Customers were moved only to their Most-Like Rate during the transition (e.g., only if a customer was already on a plan with a demand charge could they be defaulted to a plan with a demand charge).
3	Clarification	"APS's Customer Education Plan did not include any performance metrics or methodology to allow an objective determination of its success or failure…" (p. 3)	• There was no process in place for the ACC to approve metrics or targets. • However, Guidehouse agrees that the lack of performance metrics is an area of improvement for APS moving forward.
4	Clarification	"While APS's response touted its success or "effectiveness" […] based, in part, on the fact that 22.8% of residential customers voluntarily switched to a new service plan […] it is not possible to determine if this switch rate was reasonable or not." (p. 3)	• An analysis of three California default residential rate transitions shows *lower* percentages of customers who voluntarily switched to different plans, indicating that APS was successful as measured by the 22.8% switch rate.[6]
5	Clarification	"Other data suggests that APS's communications designed to educate customers about their "best" or "most economical" plan have not been successful." (p. 4)	• Without reference to a specific target or industry standard, the data cited does not indicate APS's communications were unsuccessful. • Customers were educated about their most economical plan (MEP) and also

[5] The annual rate reassignment process may move a customer on a Basic (flat) rate to a TOU energy-based rate (not demand-based), when that customer exceeds the eligible Basic rate consumption level based on 12 months of consumption data (going from 601-999 kWh/month to 1,000 kWh/month or above).
[6] Approximately 20% of residential customers in SCE's 2018 default TOU pilot voluntarily switched rates during the pre-enrollment period, opting out of TOU. In SDG&E's full residential default TOU transition, 16.1% of customers opted-out of the default rate onto another rate, including another TOU rate, by the end of Q1 2020.

#	Issue Type	Reference	Guidehouse Comments
			encouraged to select the rate plan that was best for them based on their own values and preferences.
6	Correction	"APS's Education Plan relied primarily on its experience in explaining demand rates and demand rate plans to its customers when these rate options were voluntary…" (p. 5)	• Demand rates remain voluntary, so APS's reliance on its experience with voluntary demand rates was appropriate. • APS also included educational content to explain demand rates throughout the CEOP implementation.
7	Clarification	"The fact that so many customers are being served by plans for which they are no longer qualified based on their historical usage suggests a concern with the efficacy of APS's Education Plan." (p. 6)	• APS could have communicated to customers more about changes that could occur outside the transition process. • However, Guidehouse does not agree that re-aligning large residential customers with new plans that fit their consumption indicates shortcomings of the APS 2017 CEOP.
8	Clarification	"APS has not updated its Education Plan or undertaken steps to update its Customer Education goals and objectives […] Rather, APS has developed what it refers to as various "plans" for marketing of various approved APS programs […] these documents do not include any of the key components of an education plan as set forth in this Report." (p. 7)	• The APS 2017 CEOP was developed specifically for the rate transition completed by May 1, 2018. • APS has developed a number of marketing plans for other programs, but these fall outside of the scope of the rate transition. Guidehouse is not aware of any requirements for these plans to conform to the components identified in the Alexander Report.

Comparison to California and SCE's Residential Rate Reform Transition

Guidehouse reviewed the reasonableness of the assertion made in the Alexander Report that "the Marketing, Education, and Outreach (ME&O) plans developed by the California investor owned electric utilities to implement the Time of Use rate mandate for residential customers" should serve "as the basis for comparing the APS Plan to 'best practices.'"

Guidehouse's analysis concludes that the two plans differ significantly in terms of scope, scale, and budget. Thus, while the California utility ME&O experience contains some valuable insights for future APS customer education and outreach initiatives, any discussion of the two should clearly explain the relevant similarities and differences. Furthermore, because of the significant differences identified here, an *ex post facto* evaluation of the APS CEOP against the California IOU ME&O plans is not appropriate.

As the Alexander Report notes, California's three largest IOUs, Pacific Gas & Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E), have embarked on an ambitious ME&O campaign to support California's 10.5 million qualified residential customers in making the major shift from tiered,[7] non-time differentiated rates to default TOU rates in a few short years. The Alexander Report points to SCE's ME&O plan as its primary example of best practices, so Guidehouse primarily conducted much of its assessment in comparison to SCE's ME&O activities.

Guidehouse identified four critical structural differences between SCE's TOU rate transition and APS's rate transition that make comparing these two examples problematic and, without a full and accurate understanding of both the California and APS rate transitions, potentially misleading. The APS and SCE rate transitions had fundamentally different:

1. **Customer starting places:** Following years of divergent rate offerings and education, SCE's and APS's residential customers started their respective transitions at very different pre-existing levels of understanding and experience with TOU rates. Overall, SCE's customers were undergoing a fundamental change transitioning from tiered rates to default TOU rates. Conversely, the majority of APS's customers, already having been on TOU rates, were facing an important but more evolutionary transition that was a continuation of longstanding trends and policy. Further, no APS customers were involuntarily moved or otherwise defaulted to TOU rates in the rate transition itself.
2. **Customer educational needs:** SCE's TOU ME&O plan is designed to help transition nearly all of its residential customers from non-time differentiated rates to TOU rates – a significant change, particularly in such a short time period – whereas APS's CEOP was designed to help transition the vast majority of its residential customers to rates that were structurally similar to their previous rates (the Most-Like Rate).
3. **Policy objectives and Commission directives:** While SCE was embarking on transitioning nearly all its residential customers from non-time differentiated rates to TOU rates, the majority of APS's residential customers had already been on TOU rates for more than a decade.[8] This important difference led the Commissions in Arizona and California to order their respective utilities to develop outreach plans with differing levels of specificity and prescription.
4. **Customer education budget size and complexity:** The California Public Utilities Commission (CPUC) authorized a default ME&O budget for SCE that was much larger and more complex than APS's CEOP budget (SCE budgeted more than $70 million for 2017-2020, compared to $5 million for APS) because SCE's rate transition was meaningfully different in its size, complexity, and breadth compared to APS's rate transition.

Utility Education & Outreach Best Practices

Beyond California, many utilities are moving towards modernizing their rates and leveraging digital tools and advanced data capabilities to enhance customer experiences, including education and outreach. Utilities are proceeding cautiously during this transition and are often hindered by technical challenges and evolving best practices. Furthermore, regulatory

[7] Tiered electricity rates have multiple price tiers based on consumption levels, each with a different fixed $/kWh rate. When a customer's electricity consumption moves into the next tier, each additional kWh of consumption is charged at the rate for that tier.
[8] Since 2009, more than 50% of APS's residential customers have been on a TOU-energy or TOU-demand rate.

mandates and stated objectives vary by utility. These factors have resulted in a range of practices related to customer education and outreach across the US and North America.

By leveraging a range of secondary sources and our in-house expertise, Guidehouse conducted an independent review of APS's 2017 CEOP and its implementation to compare it to (1) general utility best practices and industry norms (common practices observed among utilities) and (2) best practices from behavioral science.

General Utility Best Practices

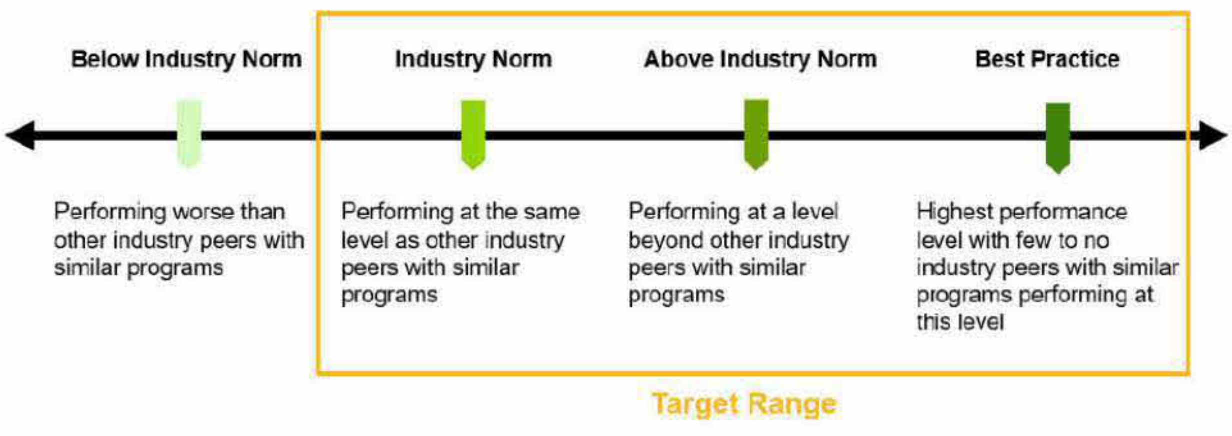
Guidehouse used a two-step process for reviewing APS's 2017 CEOP against general utility best practices:

- Identify best practices related to the CEOP's goals
- Compare the CEOP plan and implementation to-date to those best practices and to common practices (or industry norms)

Guidehouse developed a list of best practices across five topic areas: (1) communication planning, (2) communication methods, (3) message content, (4) customer resources and tools, and (5) metrics and reporting. **Guidehouse found that APS performed at industry norm in three topic areas and at best practice in two topic areas.**

To reach this finding, Guidehouse assessed APS's performance on a scale with four discrete grades:

Figure 1. Utility Education & Outreach Performance Scale



As shown above, the scale includes a range of acceptable practices based on how industry peers with similar programs performed across the five topic areas (see Chapter 3.1.1 for more information on the peer set). Table 2 provides Guidehouse's review of the 2017 CEOP and its implementation along this continuum.

Table 2. APS Performance for Outreach and Education Best Practices

Topic Area & Practices	Guidehouse Review & Rationale
Communication Planning • Conduct market research • Define message strategy by customer segment • Identify communication touchpoints	**Performed at Industry Norm** – APS implemented similar planning techniques to industry peers with similar programs, including identifying communication touchpoints, training call center staff, and coordinating with at least one other program (e.g., DSM).

Topic Area & Practices	Guidehouse Review & Rationale
• Optimize frequency and synchronize with other channels/programs • Prepare and train customer reps • Conduct soft launches	APS leveraged extensive historical customer research but did not conduct new customer research, which puts them on par with industry norm. The secondary sources Guidehouse referenced noted that market research practices were mixed, as some industry peers with similar programs conduct regular market research and others do not conduct any market research due to budget and staff constraints.
Communication Methods • Use a variety of traditional and digital marketing outlets • Employ community-based outreach (CBO), if appropriate	**Performed at Best Practice** – APS implemented a wide range and used a significant volume of traditional and digital marketing materials through multiple channels, including CBO in alignment with best practice. The final Overland Report and the APS Response to Commissioner Dunn Request confirmed this finding.
Message Content • Align rate transition and broader program marketing messages (e.g., DSM) • Set realistic bill savings expectations (for time variant rates) • Ensure bill savings and data analytics accuracy in communications and tools (e.g., bill calculators)	**Performed at Industry Norm** – APS aligned its rate transition customer education with broader program marketing, which is best practice. However, there was some evidence that customers did not understand APS's messaging on the concept of "saving" — specifically, whether simply moving to a new rate plan would save them money, as opposed to saving money by modifying their electricity consumption behaviors (in accordance with the *Shift, Stagger, Save* message). APS also had an error in its rate comparison tool from February 2019 to November 2019.[9] Although not a desirable customer experience, a US DOE study shows that industry peers with similar programs often experience issues related to messaging and technology implementation like APS.[10]
Resources & Tools • Provide bill or rate comparisons / calculators • Establish comprehensive customer portal • Use materials that engage customers • Implement bill guarantees, if budget allows and appropriate for scope of rate transition	**Performed at Best Practice** – APS provided a wide range of materials to educate and engage customers in alignment with best practice. In many cases, APS provided more materials than most industry peers with similar programs studied. For example, APS provided customers with welcome kits and the rate comparison tool, which are resources and tools that many other peers did not offer. The Overland Report also confirmed this finding.
Metrics & Reporting • Establish education and outreach goals (in alignment with industry peers with similar programs) and success criteria (in alignment with best practice) • Analyze marketing metrics • Analyze program-related metrics (in alignment with industry trends)	**Performed at Industry Norm** – APS established education and outreach goals and analyzed marketing metrics in alignment with other utilities. However, APS did not articulate success criteria, nor did it establish *program*-related metrics for the CEOP and its implementation. Although best practice, Guidehouse's research shows that implementation of these practices is mixed and therefore, APS is still in alignment with industry norm.

As shown, APS performed at industry norm or best practice in all five of the topic areas.

[9] APS has since provided refund checks to 12,971 affected customers, or approximately $1,065,000 in total refunds, which includes a $25 inconvenience credit. Additionally, based on an approach developed by a Commission consultant with which the Company does not necessarily agree, APS has also refunded an additional 3,787 customers $468,748, which includes a $25 inconvenience credit.

[10] U.S. Department of Energy, Experiences from the Consumer Behavior Studies on Engaging Customers, September 2014, https://www.energy.gov/sites/prod/files/2014/11/f19/SG-CustEngagement-Sept2014.pdf.

Behavioral Science Best Practices

Guidehouse used the same two-step process for evaluating 2017 CEOP activities against behavioral science best practices and identified a set of eight behavioral science best practices in two categories derived from a variety of behavioral research studies including utility-specific studies and more general behavioral science research.

From a behavioral science perspective, the 2017 CEOP was successful at integrating four important behavioral best practices into its outreach and education efforts. Guidehouse also identified four areas in which APS could use behavioral science insights to improve its CEOP activities. Table 3 summarizes where the APS education and outreach activities were consistent with behavioral science best practices and where educational activities could be improved through the application of behavioral science insights.

One consistent and important theme across both columns of Table 3 below is that focusing education and outreach on the Most-Like Rate is both consistent with the Settlement Agreement and best practice for this type of rate transition. In contrast, customer education and outreach that focuses exclusively on moving customers to the most economical rate plan, or MEP, ignores other considerations that can be very important to customers, and is not considered best practice. Behavioral science clearly indicates that most people tend to stay with the status quo or default option when faced with a decision. Behavioral science also indicates that for those people who do make an active choice, a wide range of non-economic factors are likely to influence the decision-making process. As a result, both economic and non-economic factors should be integrated into the tools and materials used to inform customers about their rate choices. By addressing other customer motivators as well as the MEP, customers will be able to make a more informed choice and have a better experience.

Table 3. APS Performance for Behavioral Science Best Practices

Strengths	Opportunities for Improvement
• Use of customer choice architecture in the design of rate transition defaults to account for status quo bias and ensure that customers' prior preferences are prominent in the assignment of default rates	• Customer research to better understand and more fully integrate the range of customer values and motivations into the discussion of rate comparison tools and pro forma billing
• Development of rate comparison tools and subsequent development of pro forma billing to promote rational action during customer rate selection	• Use of behavioral diagnostics to enhance the design, formatting, and content of customer bills and improve customer comprehension and behavior
• Use of (smart thermostat) sweepstakes to promote active enrollment	• Design of graphics used to communicate peak and off-peak periods in TOU rates
• Use of "nudges" such as high bill alerts, detailed energy feedback through the APS app, and rate-specific tips (via home energy reports) to shift TOU behaviors	• Application of behavioral research to enhance the effectiveness of key communications materials such as welcome kits

Conclusions and Recommendations

From our assessment of best practices summarized above and our review of the Alexander Report and other critiques by various stakeholders of APS's 2017 CEOP, Guidehouse recommends a multi-year customer engagement initiative for the rates program that incorporates the following elements over the long term, and that could support goals and objectives resulting from APS's pending rate case in the near term:

- **Relating to Customer Research and Experience:** Guidehouse recommends that APS consider conducting customer segmentation and ongoing process evaluation research for a period of 2 to 3 years prior to and following the rollout of new rates to better understand customer perspectives, motivations, barriers, and expectations and how they vary across important segments of the population. This research could be used to inform program outreach activities and materials using a continuous process improvement approach. Guidehouse recommends that APS consider opportunities for expanding its behavioral nudge efforts whenever feasible. APS should also consider additional tool enhancements that facilitate customer engagement and increase rate choice awareness.
- **Relating to Behavioral Science Review and Research:** Guidehouse recommends that future rate change CEOPs integrate both economic and non-economic factors into the tools and materials used to inform customers about their rate choices. An exclusive education and outreach plan focused on the MEP ignores other potential considerations that can be very important to some customers. Guidehouse recommends that APS perform behavioral diagnostics and research to assess how customers are evaluating rate options and determine the values that customers reference when making a choice (as well as the biases that shape their choice). APS can use such behavioral diagnostics and evaluation as a means of enhancing the formatting and content of key rate-related communications such as welcome packets, bills, and other utility communications.
- **Relating to Objectives, Metrics, and Reporting:** Guidehouse recommends that APS take a more programmatic approach to planning, implementing, and evaluating the customer response to new rates. Guidehouse recommends that APS create an evaluation plan that documents utility goals and evaluates the performance of rate-related initiatives against strategic objectives. Evaluation findings should be used to inform changes to program efforts and materials in an ongoing cycle of continuous process improvement. It is important to emphasize that metrics should not only document marketing and education outputs, but they should also reflect the behavioral science research discussed above to measure the impact of marketing and education activities on customer awareness, perceptions, knowledge, behavior, barriers, and experience.
- **Relating to Stakeholder Engagement and Input:** A regular, ongoing stakeholder engagement process – particularly in an environment where multiple programs and other factors impact rates and customer bills in different ways – is an important vehicle for ensuring transparency. Guidehouse understands that APS has already instituted a Customer Advisory Board to engage with customer representatives directly and begun recurring stakeholder meetings designed to facilitate such transparency and engagement, and strongly endorses these steps. Guidehouse recommends that APS formalize the regular stakeholder meetings into a Stakeholder Advisory Council that could serve as an important sounding board, complementary to the Customer Advisory Board, in the development and tracking of future rate plans and customer education initiatives from a regulatory perspective.

1.0 Issue Overview

Arizona Public Service Company (APS) is operating in a dynamic regulatory environment in which regulator priorities, end-use customer experiences, and cost and rate pressures are rapidly changing. In this environment, APS has come under scrutiny for its 2016 rate case implementation, specifically its customer education and outreach efforts for the rate plan transition approved in the rate case settlement. The Arizona Corporation Commission (ACC, or the Commission), APS, and stakeholders and intervenors have been working to address numerous questions and issues related to the 2017 Customer Education and Outreach Plan (CEOP) for the rate transition and its subsequent implementation in several dockets, including the 2016 Rate Case Docket(s) and a targeted 2019 Rate Review Docket.[11,12]

As APS develops its current 2019 rate case at the Commission,[13] many of the same questions and issues regarding the 2016 rate case transition and implementation of its CEOP continue to come up. In particular, the recent report *An Evaluation of Arizona Public Service Company's Customer Education Plan and its Implementation* by Barbara Alexander Consulting LLC (Alexander Report) was docketed in both the APS 2019 Rate Review Docket and the 2019 Rate Case Docket on May 19, 2020 and led to additional scrutiny on the APS CEOP at the Commission's June 18, 2020 Open Meeting.

1.1 Guidehouse Approach

APS engaged Guidehouse Inc. (Guidehouse) to provide an objective review and assessment of the 2017 CEOP and Alexander Report, and to add our perspective to the dialogue on customer education and outreach best practices related to the rollout of new rate plans.

Guidehouse's review of the Alexander Report and our broad insights into utility best practices are based on our deep experience with utility education and outreach programs, retail electric rates and related regulatory matters, and behavioral science, as well as a close review of the Alexander Report and relevant information provided in data requests and select interviews with APS staff. To bring this information together in an actionable format for APS, in this report we also provide a comparison of the 2017 CEOP and its implementation to our view of best practices and make recommendations for a future CEOP.

Guidehouse performed this review and assessment over a short period, relying on data requests and interviews with APS staff, secondary research, and in-house expertise. The scope did not include primary customer research, a detailed assessment of the rate transition period from February to May 2018, or an evaluation of the 2016 rate case or rate plans themselves. It also did not include a review or assessment of any other customer engagement and outreach plans related to other APS initiatives outside of the rate transition.

1.2 Timeline of Events

On August 18, 2017, the ACC approved the APS 2016 Rate Case under a Settlement Agreement, which included both a rate increase and new rate plans. Under Decision No. 76295,

[11] In an ACC procedural order dated 8/1/2016, Dockets E-01345A-16-0036 and E-01345A-16-0123 were consolidated for the 2016 rate case.
[12] Docket No. E-01345A-19-0003.
[13] Docket No. E-01345A-19-0236.

the Commission approved changes to modernize APS's existing rate plans and required APS to file a CEOP to educate customers about their new rate plan options.[14] This decision kicked off the customer education and outreach effort and the related stakeholder process leading up to the customer rate plan transition, which took place from February 1, 2018 to May 1, 2018. Customers were asked to select a new rate plan or, if the customer did not affirmatively select a new rate plan, the customer would be placed on the rate plan most like the customer's current rate plan (Most-Like Rate) during the transition window. For new residential customers (with monthly consumption of 600-1,000 kWh), after May 1, 2018, there was also established a 90-day trial period of time-of-use (TOU) or TOU with demand rates, after which they were eligible to choose another service plan.

Both the development of the CEOP document and opportunity for formal stakeholder feedback took place through a short three-step process defined in the Commission's decision. APS filed a draft CEOP on September 11, 2017, within 15 business days of the decision as ordered. Stakeholders were given 10 days to file comments, and a combined stakeholder group submitted its comments on September 21, 2017. The decision stated that APS would have "10 days thereafter to file a final plan," which APS filed on September 29, 2017.

APS incorporated three of the combined stakeholder comments into its final plan and also agreed to meet with stakeholders at least twice during the customer rate transition process. Noting that there were a number of comments they felt were not addressed, the stakeholder group filed concerns in a letter to the ACC on October 10, 2017; however, this letter fell outside of the process defined in Decision No. 76295. These comments, and whether or not they were eventually addressed in APS's CEOP implementation, are described later in this chapter.

APS conducted its rate transition-focused outreach and education activities from October 2017 to May 2018, and the automatic rate transition for customers who had not yet selected a new plan began February 1, 2018 and was completed by May 1, 2018, as approved in Decision No. 76295. However, on January 3, 2018, a residential customer filed a formal complaint at the Commission regarding the bill impact of the 2016 Rate Case Settlement Agreement. Guidehouse did not examine this complaint, other than to note it was dismissed on December 17, 2019,[15] but this docket does include useful informational filings by APS and also provides additional context for the scrutiny the 2017 CEOP received.

On January 9, 2019, the ACC directed the Utilities Division Staff to conduct a review of the effectiveness of APS's CEOP and to initiate a rate review of APS's current rates utilizing a 2018 test year (APS 2019 Rate Review).[16] Staff hired a consultant, Overland Consulting, to assist with the rate review and evaluation of the CEOP. The report *Rate Review and Customer Outreach Program Evaluation of Arizona Public Service Company* (Overland Report) was docketed on June 4, 2019, and identified areas of strength and areas for improvement in APS's CEOP. Guidehouse's review of the Overland Report CEOP findings is also described later in this chapter.

[14] Arizona Corporation Commission, Decision No. 76295, August 18, 2017, Docket No. E-01345A-16-0036 / E-01345A-16-0123, https://docket.images.azcc.gov/0000182160.pdf.
[15] Arizona Corporate Commission, Decision No. 77501, December 17, 2019, Docket No. E-1345A-18-0002, https://docket.images.azcc.gov/0000200417.pdf.
[16] Docket No. E-01345A-19-0003.

After the Overland Report, in Decision No. 77270 on June 27, 2019,[17] the ACC directed Commission Staff to "select and hire an independent consultant, paid for by APS, to develop a program to properly and adequately educate customers on all aspects of APS's rate plans." Commission Staff hired Barbara Alexander Consulting LLC, which resulted in the Alexander Report on May 19, 2020. This report declined to develop the program on APS's behalf and instead focused on evaluating the 2017 CEOP. The Alexander Report recommends the Commission order APS to create a new CEOP.[18]

1.3 Overview of the APS Rate Transition

When considering the 2017 CEOP document, it is important to understand the scope of the rate plan changes that were addressed via the education and outreach APS conducted. As described, the 2016 Rate Case Settlement Agreement approved a rate increase and new rate plans for APS customers. Essentially, the new rate plans were revisions of existing rate plans, with several modifications to better align rates with costs.[19] The new rate plans did not represent fundamental structural changes to APS's residential rate design (e.g., a change from flat or tiered rates to time-based rates), unless customers specifically selected a new rate structure.

According to the Settlement Agreement, APS moved customers only to their Most-Like Rate if customers did not select an alternative before the transition period began on February 1, 2018. As shown in the table below, any customer on a "flat" plan type as of August 19, 2017 (when pre-existing plans were frozen), and who did not make a selection, was transitioned across the table row to a new "flat" plan between February 1, 2018 and May 1, 2018. The overall impact on customers of this transition is generally much smaller than a global migration of customers from one rate type to a new rate type. This distinction is discussed in more detail in the next chapter.

Table 4. Most-Like Rate Plan Transition

Plan Type	Pre-August 2017 Rates	New Rates Available	New Service Plans
Flat[20]	E-12	R-XS	Lite Choice
		R-Basic	Premier Choice
		R-Basic Large	Premier Choice Large
Time of Use (TOU)	ET-1 ET-2 ET-SP ET-EV	TOU-E	Saver Choice
Demand	ECT-2 ECT-1R	R-3	Saver Choice Max

Notes: R-Basic Large was no longer available to new customers as of May 1, 2018 and to customers on another rate as of September 1, 2018. The R-2 rate, or Saver Choice Plus service plan (demand-based), was also available to customers but was not identified as a Most-Like Rate for a pre-existing plan. The new R-Tech rate (a pilot TOU rate

[17] Arizona Corporation Commission, Decision No. 77270, June 27, 2019, Docket No. E-01345A-19-0003, https://docket.images.azcc.gov/0000198805.pdf.
[18] "While this Report identifies the shortcomings of APS's Customer Education Plan, it is not my recommendation that the Commission or the Commission Staff should develop a customer education plan or implement customer education on behalf of APS." Page 7, An Evaluation of Arizona Public Service Company's Customer Education Plan and its Implementation, Barbara Alexander Consulting LLC, May 19, 2020.
[19] Modifications made to better align rates to costs included revised time of use (TOU) periods, summer/winter differential, on-peak hours (revised to be fewer), and off-peak holidays (revised for additional holidays).
[20] "Flat" rates here refer to inclining block rates, a similar rate structure to the "tiered" rates discussed in the context of the California IOUs. This is a structure with a higher rate for each incremental amount of electricity consumption.

with demand and technology requirements) was also made available to eligible customers. Additionally, legacy solar customers were not required to change rates during the transition period.

According to Decision No. 76295, new customers after May 1, 2018 could first select a TOU-E, R-2, or R-3 rate, but after 90 days could then opt-out of the rate and move to a basic rate if they qualified.

1.4 Overview of the APS 2017 Customer Education & Outreach Plan

The focus of APS's 2017 CEOP is the Most-Like Rate transition, and marketing and outreach to enable customers to make a selection proactively and encourage them to adopt their own "Best Rate" (also called the most economical plan, or MEP – the rate plan that would provide the customer with the lowest electricity bill based on the most recent year of usage data).

In the 2016 Rate Case Settlement Agreement, the Commission stated that "The CEOP should contain at a minimum, simple, easy to understand information regarding the new rate plans, the transition plan, and the plans available after May 1, 2018." It also established the following set of requirements:

- APS and stakeholders will comply with the timeline, as described (a draft CEOP within 15 business days of the Commission Decision, stakeholder feedback within 10 calendar days, and a final CEOP 10 days thereafter).
- Commission Staff will approve a final CEOP.
- The draft CEOP will include a proposed form of notice for both customers who are on another rate and new customers that informs the customers of their rate options after May 1, 2018, accompanied by information on the estimated bill impact of switching to another rate.
- For customers who are on another rate, the final approved notice must be provided to the existing customer at least 3 billing cycles prior to May 1, 2018, or the date on which APS's new rate plans commence.
- The draft CEOP will include a form of notice to inform new ratepayers subject to the 90-day trial period of their rate options at the conclusion of the trial period, including:
    - Information on the estimated bill impact of switching to another rate.
    - A suitable method for delivery of the notice so that customers will receive the notice shortly after or at the same time as their second bill (sufficient notice should the customer wish to begin taking service at that time on a flat rate plan rather than a time- or demand-differentiated rate plan).

The final CEOP filed September 29, 2017 is a 12-page document that provided a written overview of APS's plan and indicated that APS would comply with the Commission's orders pertaining to APS. The CEOP document is relatively high level; it was filed on a short timeframe and does not describe many of the specific education and outreach activities APS undertook over the course of the entire rate transition timeline. For example, the CEOP document acknowledged the requirement for providing estimated bill impacts but did not describe how that information would be noticed to customers; however, in reviewing APS's subsequent implementation of the plan, Guidehouse confirmed there were bill inserts with average bill impact estimates in the initial "Pick Your Plan" campaign and an APS.com webpage with bill impact information, as ordered.[21]

The 2017 CEOP document summarized a three-phased approach to APS's rate transition education and outreach: *Awareness*, *Transition*, and *Transition and Beyond*. The plan described customer touchpoints, or contact points, in each phase that included letters, emails, web banners, bill messages, bill inserts, website pop-ups, informational videos, voice messages, social media, and other methods. APS stated one of its main goals was to notify customers of their Best Rate and educate them on how to maximize savings on their Best Rate. At the same time, customers would be made aware of the Most-Like Rate they would be transitioned to if they did not make a selection. APS also discussed its core message of "Shift, Stagger, and Save" in the rate transition, a message that had already been promoted to customers since Fall 2016, when APS first began to prepare as part of the ongoing 2016 rate case.

More detail on APS's plan and implementation activities is provided throughout this report as it relates to Guidehouse's review and our independent assessment of education and outreach best practices.

1.5 Response to the APS Customer Education & Outreach Plan

In addition to the Alexander Report, Guidehouse reviewed the two other primary responses to APS's CEOP: stakeholder group comments filed in the 2016 Rate Case Docket and the Overland Report from the 2019 Rate Review Docket. Both sources pre-date the Alexander Report and provide additional perspectives and context.

This section briefly summarizes the stakeholder group's views and Overland Report's findings, identifies points from each that may not have been addressed to-date, and provides a preview of the Alexander Report, which is the subject of Guidehouse's deep dive in Chapter 2.0.

1.5.1 Stakeholder Comments

Throughout the 2016 Rate Case, APS held numerous stakeholder sessions to build early awareness of the rate changes it was seeking, which enabled key stakeholders to more actively and substantively participate in the rate case and subsequent settlement process, and to begin formulating their own recommendations about how customers should be approached about potential rate changes.

Finalizing the 2017 CEOP document, however, involved a comparatively limited stakeholder feedback process defined in Decision No. 76295. Stakeholders had 10 days to file a single set of comments on the CEOP, which a stakeholder group did on September 21, 2017.[22] After that, APS had 10 days to file the final plan. Although the stakeholder group followed up with concerns in a filing on October 10, 2017, this fell outside of the established process.

[21] Attachments C and G, RE: Arizona Public Service Company Docket No. E-1345A-18-0002, Formal Complaint of Stacey Champion, Response to Commissioner Dunn Request, October 26, 2018.
[22] The stakeholder group consisted of the Arizona Community Action Association, Arizona Interfaith Power & Light, Arizona PIRG Education Fund, Conservative Alliance for Solar Energy, Environment Arizona Research & Policy Center, Sierra Club - Grand Canyon Chapter, and the Southwest Energy Efficiency Project.

The stakeholder group made nine comments,[23] several of which were similarly focused on increasing APS's reporting duties to the Commission. After reviewing the stakeholder filing and meeting with the group, APS adopted recommendations for three of the nine comments in the final CEOP. Through its implementation activities, APS also addressed several of the other recommendations over time, though not explicitly linked to the stakeholder comments.

The nine comments are described in the table below, along with a high-level assessment of the status of each of the respective comments to-date. The status "adopted" refers to comments that were addressed formally in the CEOP document, while the status "implemented" refers to comments that were addressed informally through implementation activities at a later date.

Table 5. Status Assessment of the Stakeholder Group Comments

No.	Stakeholder Comment	Status	Assessment
1	APS should provide the Commission with a comprehensive set of examples of the communications that various customer classes and groups will receive and how and when they will receive that information	Partially Implemented	Examples of certain materials were included in the final CEOP, including a transition letter, welcome kit, and video screenshots. After the fact, APS also provided examples of many other marketing materials (bill inserts, emails, digital media messages, and more) to the Commission. As explained in the later October 10, 2017 filing, the underlying stakeholder concern was actually that "APS messaging is not resonating with its ratepayers" based on communications the stakeholder group had with customers. However, APS also had customer feedback from focus groups and reason to believe the messaging was resonating. This type of concern would have to be discussed in ongoing stakeholder meetings to reach some level of agreement, if possible.
2	APS should provide communications in Spanish or other languages	Adopted	APS incorporated Spanish language messaging to customers in the final CEOP. APS provided examples of outreach materials in Spanish (bill inserts, emails, and digital media messages).
3	APS should clarify if customers will be charged for text messages, and how customers can opt-out of communications if they wish not to be charged	Not Applicable	In the final CEOP, APS clarified that "customers who choose to enroll in text message notifications via aps.com may choose to opt-out at any time." However, APS reported to Guidehouse that it ultimately did not conduct any rate transition marketing using text messages. For any initiative, APS's text message

[23] The original stakeholder comments filed were presented in five categories, but were organized into nine distinct comments in the stakeholder group's October 10, 2017 filing reporting back on APS's response.

No.	Stakeholder Comment	Status	Assessment
			marketing approach is currently opt-in only.
4	APS should explain how it will incorporate messaging on the availability of energy efficiency program, services, and tools to help customers manage their rate options	Adopted	The final CEOP incorporates Demand Side Management messaging. One of the CEOP's five goals was to "familiarize customers with opportunities to save, based on their selected rate plan, through APS's core message, *Shift, Stagger and Save*, and available Demand Side Management programs." During implementation, APS focused on connecting customers with energy and demand management tools. In marketing materials, APS encouraged customers to download the APS app and visit the website (aps.com/options), which directed them to additional tools and programs.
5	APS should provide the Commission with monthly reports that provide information on the number of customers by customer class projected to and enrolled and transitioned to each rate plan. APS should provide the Commission with information on customers who are put on the default rate plan and the plan that these customers choose after the 90-day period expires. Information should be provided on the number of customers who prefer to use a plan other than the demand rate or time-of-use (TOU) rate options.	Partially Implemented	APS did not adopt the stakeholder group's recommendation for APS to report on a monthly basis to the Commission; however, APS later complied with Decision No. 77270 in the 2019 Rate Review Docket in which the Commission ordered APS to track and report similar customer information on a quarterly basis. APS noted that it would have been challenging to do monthly reporting while transitioning customers (and at the same time stabilizing a new billing system). Additionally, the Commission had not requested any reporting during the transition period.

No.	Stakeholder Comment	Status	Assessment
6	APS should provide a budget so they can understand how ratepayer money will be invested and report regularly on expenditures	Partially implemented	In response to a Commissioner request, APS provided a retrospective update on the $5 million of DSM funds spent as of October 26, 2018:[24]

Funding Category	Amount
Customer Tools	$1,361,503
Materials and Printing	$1,310,215
Rate Analysis	$1,180,080
Mass media	$661,163
Community Events	$6,012
System Integration	$310,256
Non-Residential	$9,335
Outside Services	$52,465
Total	**$4,891,029**

No.	Stakeholder Comment	Status	Assessment
7	APS should establish and approve metrics for quantifying and measuring the effectiveness of APS education and outreach activities	Partially implemented	APS tracked the following metrics: E-mails sent, welcome kits sent, mass media and aps.com service plan pages impressions, bill communications, and community events. However, these metrics are focused on marketing reach rather than program "effectiveness" which, in Guidehouse's view, would better be measured by customer awareness and understanding metrics.
8	APS should provide a written report to the Commission no later than June 30, 2018 and describe how well the plan is being executed	Not adopted	Without direction from the ACC on this topic, APS did not adopt the stakeholder group's recommendation for APS to submit a report to the Commission by June 30, 2018.
9	APS should formalize a consumer stakeholder working group that meets regularly	Partially adopted / implemented	In the final CEOP, APS stated it would meet with stakeholders at least twice during the transition process. As described in the October 26, 2018 filing in Docket No. E-1345A-18-0002,[25] APS advisors did complete a series of 17 Stakeholder Outreach meetings between July 2018 and October 2018; however, it is not clear which stakeholder groups were present and to what extent the

[24] Arizona Public Service Company, Response to Commissioner Dunn Request, Docket No. E-1345A-18-0002, October 26, 2018, https://docket.images.azcc.gov/0000193159.pdf.
[25] Arizona Public Service Company, Response to Commissioner Dunn Request, Docket No. E-1345A-18-0002, October 26, 2018, https://docket.images.azcc.gov/0000193159.pdf.

No.	Stakeholder Comment	Status	Assessment
			meetings included the kind of two-way communication that would occur in a working group. APS reports that it has now established a Customer Advisory Board and a monthly stakeholder engagement meeting.

1.5.2 Overland Report

On January 9, 2019, the ACC directed the Utilities Division Staff to conduct a review of the effectiveness of APS's 2017 CEOP and to initiate a rate review of APS's current rates utilizing a 2018 test year (APS 2019 Rate Review).[26] Staff hired a consultant, Overland Consulting, to assist with the rate review and evaluation of the CEOP. The report *Rate Review and Customer Outreach Program Evaluation of Arizona Public Service Company* (Overland Report) was docketed on June 4, 2019. Guidehouse reviewed the CEOP matters discussed in the Overland Report to provide additional and differing perspectives from the Alexander Report that followed. Guidehouse did not review any financial matters related to the rate review.

Overland Consulting's review of APS's 2017 CEOP looked at: (1) the CEOP's methods, procedures, customer reach, and understandability of information provided; (2) the effectiveness of the CEOP in meeting the objective of providing customers with complete and accurate information about the rate increase and rate plan changes approved in the Decision, including the information needed to enable customers to make informed choices and that the effect of the rate changes could vary by individual customer circumstances; and (3) whether the CEOP expenditures were reasonable and incremental.

Overall, the final Overland Report identified areas where APS's CEOP and implementation were adequate and reasonable, as well as several areas for improvement mainly in the "effectiveness" area. Guidehouse also identified a few minor inaccuracies or mischaracterizations in the Overland Report from the document review and interviews with APS, which are noted below in bold.

Overland Review of CEOP Methods, Procedures, Customer Reach and Understandability

Overland Consulting found that APS's 2017 CEOP was appropriate in the following areas:

- "The majority of the information communicated to customers in APS's CEOP was reasonable and understandable."
- "The scope of the CEOP was adequate to reach APS's entire residential customer base. APS communicated the most important information concerning the new rates and rate plans through bill inserts or direct mail pieces mailed or emailed to all customers."
- "As part of the CEOP, APS created several tools to help customers select new rate plans and to manage their electricity usage."

[26] APS 2019 Rate Review Docket No. E-01345A-19-0003.

Overland Consulting also identified several potential areas for improvement, which Guidehouse reviews below:

- There were several exceptions to APS having "complete customer reach": APS did not have customer email addresses for 45% of its residential customer base in early 2018, APS could only send marketing emails to customers who had agreed to receive them, radio and billboard advertising was limited to the Phoenix metro area, and some marketing materials were only provided in English.[27]

  Guidehouse looked further into the question of Spanish-language marketing materials, and found a few inaccuracies in the Overland Report list. APS provided newsletters, paper bills, bill messages, bill inserts, welcome kits, and Best Rate letters to customers who had previously designated a preference for Spanish-language communications; maintained a Spanish-language website; and did Spanish-language mass media through radio ads, social media, and YouTube videos.

- "APS should have included more personal customer contact or outreach efforts [...] and which plan would be of most benefit to the customer."

  Guidehouse agrees with the observation that customers could have been further segmented for more personalized communications, and that this is an area for improvement. Guidehouse also recognizes that APS has recently begun providing customers with pro-forma billing that provides all customers with monthly information about their MEP. Customers who receive Home Energy Reports from Oracle's Opower platform are also receiving tailored tips based on their household's energy use practices and choice of rate plan.

- "APS did not explain the adjustor mechanisms in its CEOP" or "clarify the fact that there would be annual updates to the adjustor mechanism billing rates occurring outside of the rate case and that such rate changes may results in an increase in customer bills."

  In Guidehouse's view, APS could have included in its education materials more information about other rate changes such as updates to adjustors that could have had an impact on customer bills during or after the transition period. There is a balance, however, between educating customers about the myriad of factors that impact rates, and providing actionable information about significant changes that would take customers time to understand and internalize. The use of adjustors, for example, is a well-established but comparatively complex rates mechanism that was already in place.

Overland Review of CEOP Effectiveness

In this category, Overland Consulting mainly identified potential areas for improvement, which Guidehouse reviews below:

- Some customers complained about or were confused by the estimated average bill increase from the approved rate increase, the timing of the rate increase vs. the rate

[27] Identified in the Overland Report as: Emails, aps.com transactional pages, aps.com banner ads and pop-ups, IVR-based plan assistance, special interest letters, mass media campaigns, notifications, (service) plan comparison tool, and peak demand calculator.

transition, being moved to new rate plans with different peak hours, and bill impacts from being moved to new rate plans.

The Overland Report makes a common error in this finding, when it specifically cites that "Some customers were unhappy with being placed on rate plans with a demand component" when in fact no customers were moved to a rate plan with a demand component unless they were already on a rate plan with a demand component (the Most-Like Rate). Similarly, customers were not "moved to new, sometimes differently structured rate plans" during the rate transition; changes to their Most-Like Rates were minor.[28]

However, the existence of these complaints does indicate that the educational material was not effective for some customers. Some level of customer confusion is common for territory-wide changes in utility rates, and given the complexity of the Commission-approved changes, the concerns expressed by customers are not unusual. Some of the confusion may also be attributed to the annual rate reassignment process for certain customers on the Basic (flat) rates being conflated with the rate transition.[29]

- "The information provided by APS in its rate increase notices and personalized letters failed to convey certain important information [...] The information conveyed did not include that these additional increase in bills were dependent on customer-specific circumstances, including the specific rate plans customers were on before and after the transition, and behavioral changes in energy usage patterns under the new rate plans which could minimize bill increases, such as shifting usage to accommodate the new on-peak hours and demand charges."

It is Guidehouse's understanding that APS did consistently educate customers about energy usage and savings, as part of the focus on Demand Side Management and within the core message of *Shift, Stagger and Save.* Three of the five goals of APS's CEOP specifically addressed this topic. However, Guidehouse agrees that there was evidence that some customers did not understand APS's messaging on the concept of "saving" — specifically, whether simply moving to a new rate plan would save them money, as opposed to saving money by modifying their electricity consumption behavior.

- Specific issues with solar customers including that "APS's CEOP messaging did not inform solar customers or applicants of the August 31, 2017 deadline for changing their legacy rate plans," a lack of information on the potential advantages or disadvantages of changing rate plans, and the absence of legacy rate plans or retail net metering in the rate comparison tool.

APS reported to Guidehouse that it did try to inform solar customers of the deadline and potential advantages and disadvantages of different rates, but that the main communication channel to solar customers was solar installers. However, Guidehouse agrees that an area of improvement would be to message

[28] Minor changes to the summer/winter differential, on-peak hours, and off-peak holidays.

[29] The annual rate reassignment process may move a customer on Basic (flat) rates to a TOU energy-based rate (not demand-based), when that customer exceeds the eligible Basic rate consumption level based on 12 months of consumption data (going from 601-999 kWh/month to 1,000 kWh/month or above).

solar customers directly and rely less heavily on third parties. This is particularly important for those customers planning to install solar but who did not yet have an installer relationship.

Overland Review of CEOP Expenditures

Overland Consulting found that APS's 2017 CEOP was appropriate in all expenditure areas:

- "Overall, CEOP expenses incurred between September 2017 and February 2019 appear to have been reasonable, directly related to CEOP activities, and incremental to the CEOP effort."
- "The expenses associated with the three largest CEOP vendors, accounted for 62% of total CEOP vendor costs, were directly applicable to CEOP efforts and services. These costs were properly incurred and incremental to the CEOP and appropriate within the scope of the CEOP."
- "Internal cost allocations and transfers charged to CEOP were appropriate."

1.5.3 Alexander Report

In Decision No. 77270 on June 27, 2019,[30] approximately two weeks after the Overland Report was issued, the ACC directed Commission Staff to "select and hire an independent consultant, paid for by APS, to develop a program to properly and adequately educate customers on all aspects of APS's rate plans." Commission Staff hired Barbara Alexander Consulting LLC, which resulted in the Alexander Report on May 19, 2020.

As mentioned, this report did not develop the program on APS's behalf and focused on evaluating the 2017 CEOP. Instead of direct involvement in program development, the Alexander Report recommended the Commission order APS to create a new CEOP, but with clearly-defined expectations from the Commission about rate design education and integration with other programs.[31]

The Alexander Report compared APS's 2017 CEOP to "best practice" based on the Marketing, Education, and Outreach (ME&O) plans developed by the California investor-owned utilities (IOUs) to implement TOU rates for residential customers. Based on this comparison specifically, the Alexander Report found that the CEOP was missing many key attributes. Further, the Alexander Report made several broad criticisms, such as "APS's customer education plan did not conform to best practices" and "APS's demand charge rate education has been faulty," which have now been echoed by intervenors and others.

In the next chapter, Guidehouse closely examines the Alexander Report findings and the basis for comparison to best practices. Guidehouse provides counterpoints to the Alexander Report in many areas and explains how our view of the applicability of the ME&O plans developed by the California IOUs differs significantly from the Alexander Report.

[30] Arizona Corporation Commission, Decision No. 77270, June 27, 2019, https://docket.images.azcc.gov/0000198805.pdf.

[31] "While this Report identifies the shortcomings of APS's Customer Education Plan, it is not my recommendation that the Commission or the Commission Staff should develop a customer education plan or implement customer education on behalf of APS." Page 7, An Evaluation of Arizona Public Service Company's Customer Education Plan and its Implementation, Barbara Alexander Consulting LLC, May 19, 2020.

2.0 Review of the Alexander Report

In this chapter, Guidehouse provides an assessment of the arguments put forth in the May 19, 2020 report *An Evaluation of Arizona Public Service Company's Customer Education Plan and its Implementation* by Barbara Alexander Consulting LLC (Alexander Report). The first section summarizes Guidehouse's findings from our review of key statements regarding the APS CEOP and its implementation, specifically to identify inaccuracies or mischaracterizations about what occurred leading up to and during the rate transition process.

The second section takes a closer look at the basic premise of the Alexander Report, that the ME&O plans developed by the California IOUs should serve as the basis for comparing APS's CEOP to best practice. Fundamentally, Guidehouse disagrees that this is a reasonable comparison for several reasons explained in detail in our analysis.

While these sections highlight important areas where Guidehouse's analysis and conclusions differ from the Alexander Report, there are also valuable recommendations put forth in the Alexander Report that should not be dismissed. Guidehouse's recommendations presented in Chapter 4.0 reflect many of the same themes, showing better alignment with the Alexander Report on a forward-looking basis.

2.1 Alexander Report Corrections & Clarifications

The following table identifies the statements in the Alexander Report that Guidehouse believes should be corrected or clarified within the narrative around the APS CEOP and its implementation. The statements selected for inclusion in this table were taken from the executive summary, in order of appearance, and are intended to be illustrative of key concepts described in that report.

Table 6. Identification of Issues in the Alexander Report

#	Issue Type	Reference	Guidehouse Comments
1	Clarification	"APS submitted its draft plan to Stakeholders. However, most of the comments from consumer organizations were ignored in the final version of the Plan." (Page 2)	APS met with the stakeholder group and explicitly adopted three of the nine recommendations in the final 2017 CEOP document. APS and stakeholders were working on a short timeframe, as they had only 10 calendar days to evaluate and adopt recommendations or resolve differences. In its customer education and outreach implementation activities, APS also appears to have addressed the substance of five other comments. Guidehouse's review of the stakeholder comments may be found in Chapter 1.5.1.
2	Correction	"As a result of the strict limitations associated with service under the flat rate options due to their annual usage limitations, it was assumed that the vast majority of customers who had not voluntarily selected a time of use or demand charge plan in the past would be moved to a time	Customers could not be involuntarily moved to demand rates either during the rate transition or during APS's annual rate reassignment process. Customers also could not be moved to TOU rates for the first time as part of the rate transition. For the rate transition,

#	Issue Type	Reference	Guidehouse Comments
		of use or demand side for the first time." (Page 2)	customers were moved only to their Most-Like Rates. However, this statement may be referring to APS's annual rate reassignment process, which is separate from the transition process and can result in certain customers being moved to a TOU rate if they are no longer eligible for a Basic rate due to increased electricity consumption, as measured over a 12-month period.
3	Clarification	"APS's Customer Education Plan did not include any performance metrics or methodology to allow an objective determination of its success or failure in meeting its stated objectives." (Page 3) "None of the APS internal performance tracking metrics or results were included in the Education Plan and not all of them are related to the Education Plan's implementation. Nor has the Commission approved the "targets" that APS established for itself in these metrics." (Page 4)	Guidehouse notes that there was no process in place to approve metrics or targets by the Commission either at the beginning of the process or later when APS established internal performance tracking metrics. However, Guidehouse agrees that the lack of performance metrics is an area of improvement for APS going forward. APS's performance tracking metrics are focused on marketing reach rather than program "effectiveness" which, in Guidehouse's view, would better be measured by customer awareness and understanding metrics.
4	Clarification	"While APS's response touted its success or "effectiveness" in a later communication to the Commission based, in part, on the fact that 22.8% of residential customers voluntarily switched to a new service plan during the transition period, the actual Plan itself does not establish any goals or objectives to reflect customer switch rates. As a result, it is not possible to determine if this switch rate was reasonable or not." (Page 3)	As mentioned, Guidehouse agrees that the lack of performance metrics is an area of improvement for APS, but we do believe that the 22.8% switch rate demonstrates success, based on how many customers responded to APS's education and outreach by taking action. That said, there are also other measures of "success" that should also be clearly defined and agreed by parties. 22.8% of residential customers voluntarily switched to a new service plan; 15.3% chose a new service plan without assistance and 7.5% did so after speaking with an APS representative. An analysis of three California default residential rate transitions shows *lower* percentages of customers who voluntarily switched to different service plans, which suggests that APS's 22.8% is at least as good as, if not better than, the results

#	Issue Type	Reference	Guidehouse Comments
			achieved through other programs' customer education efforts.[32]
5	Clarification	"Other data suggests that APS's communications designed to educate customers about their "best" or "most economical" plan have not been successful. As of the September 2019 mailing to residential customers, 400,008 customers were informed that they were not on the most economical plan, 36% of APS's residential customers." (Page 4)	APS educated customers about the MEP, but moved any customers who did not make a selection to their Most-Like Rate, *not* their MEP, during the rate transition as approved in the Settlement Agreement. Because of the nature of the rate transition and customer behavior, it is misleading to cite the 36% of customers who received a mailing about not being on their MEP as a failure when that was not a goal or target established. Behavioral science research also shows that some customers do not select the MEP even when making a proactive choice, and may prefer another rate for other reasons (see Chapter 3.2).
6	Correction	"APS's Education Plan relied primarily on its experience in explaining demand rates and demand rate plans to its customers when these rate options were voluntary […]" "But the Plan did not include specific messages or educational content to explain the demand rate plans or how the rate-specific criteria to move customers into those plans would be explained to affected customers." (Page 5)	Demand rates remain voluntary. APS did not involuntarily move any customers to demand rates during the rate transition or at any time afterwards, which means that APS's reliance on its experience with voluntary demand rates was appropriate. APS also included educational content to explain the demand rates throughout the CEOP implementation. Additionally, APS has a robust DSM program that also includes rates messaging and customer tools. APS reported to Guidehouse that the DSM group focuses on the combination of three key factors: energy and demand education, enabling tools, and the right rate for customers.
7	Clarification	"While not discussed in the Education Plan, APS conducts an annual review of those customers who are no longer qualified for the customer's current rate plan and changes that customer's rate plan without explicit customer approval." "The fact that so many customers are being served by plans for which	APS could have communicated to customers more about changes that could occur outside rate transition process. However, while there is an annual rate reassignment process as described previously, this is a standard utility practice and does not fall within the scope of the rate transition CEOP.

[32] See 4.0Appendix A: Residential Rate Transition Switch Rates. Approximately 20% of residential customers in SCE's 2018 default TOU pilot voluntarily switched rates during the pre-enrollment period, opting out of TOU. In SDG&E's full residential default TOU transition, 16.1% of customers had opted-out of the default rate onto another rate, including another TOU rate, by the end of Q1 2020.

#	Issue Type	Reference	Guidehouse Comments
		they are no longer qualified based on their historical usage suggests a concern with the efficacy of APS's Education Plan." (Page 6)	Customers' electricity consumption changes for a variety of reasons. Guidehouse does not agree that moving large residential customers to new plans that fit their consumption level reflects shortcomings with the 2017 CEOP for the rate transition.
8	Clarification	"APS has not updated its Education Plan or undertaken steps to update its Customer Education goals and objectives since the end of the transition period covered by the 2017 Plan. Rather, APS has developed what it refers to as various "plans" for marketing of various approved APS programs (for example, home performance, DSM, energy education, safety net, and other routine customer communications for ongoing initiatives). However, these documents do not include any of the key components of an education plan as set forth in this Report." (Page 7)	Guidehouse understands that APS developed the 2017 CEOP specifically for the rate transition completed in 2018. Although APS may update the plan or create a new plan for future rate changes, this falls outside of the 2017 CEOP scope as defined. APS has also developed a number of marketing (and in-depth implementation) plans for important DSM initiatives and other programs. These also fall outside of the scope of the rate transition CEOP; however, in cases such as the DSM program, there is complementary messaging and education about rate plans. Guidehouse is not aware of any requirements for these plans to conform to the components identified in the Alexander Report.

2.2 Comparison to California and SCE's Residential Rate Reform Transition

This section of Guidehouse's report considers the reasonableness of the assertion made in the Alexander Report that "the Marketing, Education, and Outreach (ME&O) plans developed by the California investor owned electric utilities to implement the Time of Use rate mandate for residential customers" should serve "as the basis for comparing the APS Plan to 'best practices.'"[33,34]

Guidehouse's analysis concludes that the two plans differ significantly in terms of scope, scale, and budget. Thus, while the California utility ME&O experience contains some valuable insights for future APS customer education and outreach initiatives, any discussion of the two should clearly explain the relevant similarities and differences. Furthermore, because of the significant differences identified here, an *ex post facto*

[33] Page 1, An Evaluation of Arizona Public Service Company's Customer Education Plan and its Implementation, Barbara Alexander Consulting LLC, May 19, 2020.
[34] The Alexander Report describes the California TOU transition as a "mandate". This is not accurate. California's transition to TOU rates takes a default enrollment approach, meaning customers may opt-out of the TOU rate onto the otherwise applicable rate for which they are qualified. Under a mandate, customers do not have another rate option to fall back on. See CPUC Decision 15-07-001, also cited in Alexander Report, for details.

(retrospective) evaluation of the APS CEOP against the California IOU ME&O plans is not appropriate.

As the Alexander Report notes, California's three largest IOUs, Pacific Gas & Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E), have embarked on an ambitious ME&O campaign to support California's 10.5 million qualified residential customers in making the major shift from tiered, non-time differentiated rates to default TOU rates in a few short years.[35,36] However, there are multiple reasons why specifically comparing APS's CEOP to California's ME&O campaign is problematic and, without a full and accurate understanding of both the California and APS rate transitions, potentially misleading.

The Alexander Report points to SCE's ME&O plan as its primary example of "best practices," so Guidehouse primarily conducted much of its assessment in comparison to SCE's ME&O activities.[37] The Alexander Report also references other California-wide activities in conducting its comparison. Following the Alexander Report's approach, Guidehouse also includes other rate transition-related activities in California that extend beyond the default TOU enrollment but were still included within the scope of the SCE ME&O plan referenced by the Alexander Report. We do this to further contrast why the California ME&O program is not a reasonable comparator for APS's CEOP.

Below, Guidehouse briefly outlines the four critical structural differences between SCE's TOU rate transition and APS's rate transition that make comparing these two examples generally inaccurate and unhelpful. The APS and SCE rate transition had fundamentally different:

1. **Customer starting places:** Following years of divergent rate offerings and education, SCE and APS's residential customers started their respective transitions at very different pre-existing levels of understanding and experience with TOU rates. Overall, SCE customers were undergoing a fundamental change transitioning from tiered rates to default TOU rates. Conversely, the majority of APS's customers, already having been on TOU rates, were facing an important but more evolutionary transition that was a continuation of longstanding trends and policy. Furthermore, no APS customers were involuntarily moved or otherwise defaulted to TOU rates in the rate transition itself.
2. **Customer educational needs:** SCE's TOU ME&O plan was designed to help transition nearly all of its residential customers from non-time differentiated rates to TOU rates – an enormous change, particularly in such a short time period – whereas APS's CEOP was design to help transition the vast majority of its residential customers to rates that were structurally similar to their previous rates (the Most-Like Rate).
3. **Policy objectives and Commission directives:** While SCE was embarking on transitioning nearly all its residential customers from non-time differentiated rates to TOU rates, the majority of APS's residential customers had already been on TOU rates for more than a decade.[38] This important difference led the Commissions in Arizona and

[35] FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental.
[36] Tiered electricity rates have multiple price tiers based on consumption levels, each with a different fixed $/kWh rate. When a customer's electricity consumption moves into the next tier, each additional kWh of consumption is charged at the rate for that new tier.
[37] Page 1, An Evaluation of Arizona Public Service Company's Customer Education Plan and its Implementation, Barbara Alexander Consulting LLC, May 19, 2020.
[38] Since 2009, more than 50% of APS's residential customers have been on a TOU-energy or TOU-demand rate.

California to order their respective utilities to develop outreach plans with differing levels of specificity and prescription.

4. **Customer education budget size and complexity:** The California Public Utilities Commission (CPUC) authorized a default ME&O budget for SCE that was much larger and complex that APS's 2017 CEOP budget because SCE's rates transition was meaningfully different in its size, complexity and breadth compared to APS's rate transition.

To conduct its comparison of APS's residential rate transition to the California and SCE residential rate reform transition referenced in the Alexander Report, Guidehouse first revisits and adds to the description of APS's residential rates transition. This detailed description is designed to ensure stakeholders have a clear and correct understanding of the APS rates. Next, Guidehouse provides an overview of SCE's residential rate transition from tiered rates to default TOU rates. Providing an accurate understanding of this transition is also important for assessing the validity of comparing APS's transitions with SCE's, and where the comparison is reasonable and where – and why – it is not.

Following the description of APS and SCE's residential rate transitions, Guidehouse provides an analysis of each of the four key structural differences (outlined above) between the utilities' residential rate transitions that makes comparing the two problematic. In each section describing the structural differences, Guidehouse summarizes our assessment of the reasonableness and appropriateness of the comparison between the two utilities.

2.2.1 Description of APS's Residential Rate Transition

To understand why the comparison between SCE and APS is not fully appropriate – and is potentially misleading – it is important to understand each utility's residential rate transition and the critical differences between the two.

We begin with a summary of APS's 2018 Rate Transition. Although APS's rate transition had several facets, the key changes for the vast majority of APS's roughly 1.1 million residential customers involved the following:

- **Defaulting customers to their "Most-Like Rate" if they did not select an alternative rate for which they were qualified:** Customers who met the relevant requirements were defaulted to new versions of the rate most structurally similar to their existing rate. For example, customers on flat rates were transitioned to updated versions of the flat rate if they met the newly approved consumption threshold cut-offs. Similarly, customers on *non-demand* TOU rates were transitioned to the new version of the non-demand TOU rate while customers on *demand-based* TOU rates were transitioned to the new version of the demand-based TOU rate.

- **Rate Price Change:** All customers experienced new rate pricing (i.e., a rate increase), per the outcome determined in Decision No. 76295.[39]

[39] Settlement Sections 3 and 4.1a, pg. 8 of Settlement; Page 131/434 in Decision No. 76295.

- **New TOU Periods:** Customers on TOU rates also experienced new TOU periods and several other modifications to peak hours and the summer/winter differential, per the outcome determined in Decision No. 76295.[40]

The above summary of APS's rate transition comes from a synthesis of several sections of the March 27, 2017 Settlement Agreement. For clarity and transparency, the key Settlement Sections are provided below.

- **Defaulting customers to their Most-Like Rate if they did not select an alternative:**
    - XIX. RESIDENTIAL RATE AVAILABILITY, Section 19.1 (pg. 20 of 32)
        - "All customers may select R-Basic, R-Basic Large, TOU-E, R-2, R-3, R-Tech or R-XS if they qualify until May 1, 2018, except to the extent grandfathered under other sections of this Settlement Agreement. Distributed Generation customers will not be eligible for R-XS, R-Basic or R-Basic Large. After May 1, 2018, R-Basic Large will no longer be available to new customers or customers who are on another rate. New customers after May 1, 2018 may choose TOU-E, R-2, R-3 or if they qualify, R-XS or R-Tech. After 90 days, new customers may opt-out of their current rate and select R-Basic if they qualify. Customers transitioning to R-Basic must stay on that rate for at least 12 months."
    - XXVI. EFFECTIVE DATE OF RATE PLANS AND TRANSITION PLAN, Section 26.1 (pg. 24 of 32)
        - "The rate increase will go into effect on the effective date of the Commission's Decision in this case using transition rates which for purposes of this Agreement are defined as existing Residential and extra small General Service rate schedules with updated revenue requirements. Customers will have the opportunity to select any rate which they qualify for, and APS will provide them information on options that would minimize their bill. ***Customers that do not select a different rate will transition to the updated rate plan most like their existing rate on or before May 1, 2018***. At least 90 days before transitioning customers who have not selected a rate, APS will provide a report to the ACC indicating the total number of customers who have not made a selection."
- **Rate Price Change:**
    - III. RATE INCREASE, Section 3.1 (pg. 8 of 32)
        - "APS shall receive a $87.25 million non-fuel, non-depreciation revenue requirement increase. When the reduction for base fuel of $53.63 million and the increase for depreciation of $61.00 million is taken into account, the result is a net base rate increase of $94.624 million, exclusive of the adjustor transfer described below in Paragraph 3.2."
    - IV. BILL IMPACT, Section 4.1a (pg. 8 of 32)
        - "Residential customers will have on average a 4.54% bill impact"

[40] Settlement Section 17.8, pg. 19 of Settlement; Page 142/434 in Decision No. 76295.

- <u>XVII. RESIDENTIAL RATE DESIGN</u>, Sections 17.1 – 17.7 (pg. 17-18 of 32)
  - *Individual rate summaries for each of the seven rates proposed in the Settlement Agreement*
- <u>Settlement Agreement Appendix F</u>
  - *Proposed tariff sheets for: R-XS, R-Basic, R-Basic Large, TOU-E, R-2, R-3 Rate Schedules, R-Tech Pilot Rate*

- **New TOU Periods:**
  - <u>XVII. RESIDENTIAL RATE DESIGN</u>, Sections 17.8 (pg. 18 of 32)
    - "The on-peak period will be 3:00 pm - 8:00 pm weekdays for TOU-E, R-2, R-3, and R-Tech, excluding holidays specified in Appendix F."

Below, Figure 2 and Table 7 depict the high-level rate transitions, along with their rate names, that residential customers made between February 1, 2018 and May 1, 2018 to their Most-Like Rate. Figure 2 is taken directly from the final CEOP, and APS subsequently named the plans.

Figure 2. "Most-Like Rate Transition Plan" from the APS CEOP[41]

CURRENT	FUTURE
E-12	**R-XS, R-Basic/Large**
ET-1, ET-2	**TOU-E**
ECT-1R, ECT-2	**R-3**

Table 7. APS Most-Like Rate Plan Transition with New Service Plan Names

Plan Type	Pre-August 2017 Rates	New Rates Available	New Service Plans
Flat	E-12	R-XS	Lite Choice
		R-Basic	Premier Choice
		R-Basic Large	Premier Choice Large
Time of Use (TOU)	ET-1	TOU-E	Saver Choice
	ET-2		
	ET-SP		
	ET-EV		
Demand	ECT-2	R-3	Saver Choice Max
	ECT-1R		

As shown, customers on a flat rate (E-12) were transitioned to new versions of APS's flat rates (R-XS, R-Basic, and R-Basic Large), if they met the 12-month usage threshold criteria. Similarly, customers on non-demand TOU rates (ET-1, ET-2) would move to TOU-E while customers on demand-based TOU rates (ECT-1R, ECT-2) would move to R-3. Again, all these

[41] "Final Customer Outreach and Education Plan," APS, September 29, 2017, pg. 2.

transitions only took place on a customer's behalf if they did not make a choice of their own to move to another qualified service plan.

It is also critical to note that the transition to Most-Like Rates meant that, on the whole, APS's rate transition was not fundamentally about moving customers to rates with entirely new structures or that required significantly different behavioral changes compared to those associated with the prior rate. Instead, the focus of this rate change was primarily to keep customers on rates similar to ones they were already familiar with. Only customers that proactively selected a new rate would have seen significant structural changes.

It is important to note, however, that with the new rate requirements described in Section 19.1 and 26.1 of the Settlement Agreement (which set out new flat rate requirements and the "90 day trial" period for new customers to try a TOU rate before being able to move to a flat rate), residential customers were now being pointed to TOU and demand rates in a manner that was different than the past. Over time, this shift, along with the reduction in the number of on-peak hours and the introduction of a super-off peak winter time period, was anticipated to gradually move greater numbers of customers to TOU and demand rates.

2.2.2 Description of SCE's Rate Transition

Unlike APS's rate transition, SCE's rate transition, and the ME&O effort to support it, is characterized by a near-total transformation of its residential rates.

The scope and timing of California's rate transitions are contained in a series of decisions and resolutions under the California Public Utility Commission's (CPUC's) Residential Rate Reform Rulemaking (R.12-06-013). This expansive reform-oriented proceeding was launched in 2012, guided by landmark state legislation, characterized by deep Commissioner and Staff involvement, supported by multiple Commission mandated working groups and shaped by dozens of stakeholder groups.

The breadth and depth of the CPUC's scope in the rulemaking is captured in the summary of its Order Instituting Rulemaking from June 2012:

> "*The Commission seeks to explore if the current rate structure is meeting the stated objectives or whether alternative rate designs other than an inclining block rate can better achieve all of these objectives. Moreover, the Commission opens this rulemaking to examine whether the current tiered rate structure continues to support the underlying statewide-energy goals, facilitates the development of technologies that enable customers to better manage their usage and bills, and whether the rates result in inequitable treatment across customers and customer classes. The Commission seeks involvement in this proceeding from a variety of participants, including electric utilities, consumer advocates including advocates for low-income and disabled persons, environmental advocates, third party vendors and service providers, the California Independent System Operator, the California Energy Commission and other parties impacted by these policies.*"[42]

The CPUC's focus on the exploration of a potential transition to "time-variant and dynamic pricing" is identified in the Rulemaking's first ordering paragraph:

> "*1. An Order Instituting Rulemaking is instituted on the Commission's own motion for the purpose of examining current residential electric rate design, including the tier structure in effect for residential customers, the state of dynamic pricing, potential pathways from tiers to time-variant*

[42] CPUC, R. 12-06-013, pg. 2.

and dynamic pricing, and optimal residential rate design to be implemented when statutory restrictions are lifted."[43]

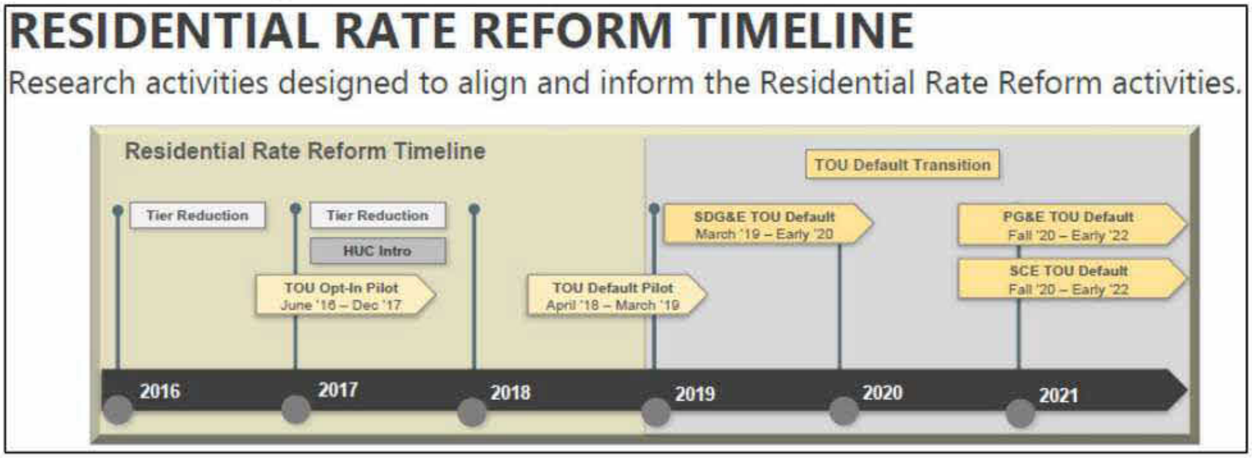
It is important to note that at the time the CPUC was beginning its exploration of "time-variant" rates, several utilities in Arizona, including APS, already had decades of experience transitioning large numbers of their residential customers to TOU rates.[44]

Under this rulemaking, California's approach to residential rate reform unfolded through a multi-year, multi-pilot, multi-stakeholder public process. Figure 3 shows the high-level timeline of California's rate reform transformation, which is characterized by the following key elements:

- **Changes to residential tiered rates**
    - 2016-2017: Tier collapse and reduction in tier differentials
    - 2017: Introduction of a "High Usage Charge" (HUC) for customers using above a certain threshold
- **Mass rollout of residential TOU rates**
    - 2016-2017: Launch of an opt-in TOU pilot to develop learnings for eventual likely default to TOU rates[45]
    - 2018-2019: Launch of a default TOU pilot to further refine marketing, education and outreach, and other operational capabilities prior to a full default TOU transition
    - 2019-2020: Residential mass market rollout of default TOU rates, away from tiered rates

[43] CPUC, R. 12-06-013, pg. 26-27.
[44] See "A Bibliography on Dynamic Pricing and Time-of-Use Rates Version 2.0v", Toni Enright and Ahmad Faruqui, January 2013 for summary of TOU rates, including those from Tucson Electric Power; See "There and Back Again", Leland Snook and Meghan Grabel, Utility Fortnightly, November 2015, pg. 46-62.
[45] California's rate reform legislation (AB 327) prohibited the transition to residential default TOU rates until 2018. To develop learnings ahead of that date, California's three largest IOUs launched opt-in residential TOU pilots to help inform the expected transition to default TOU rates.

Figure 3. California Residential Rate Reform Timeline[46]

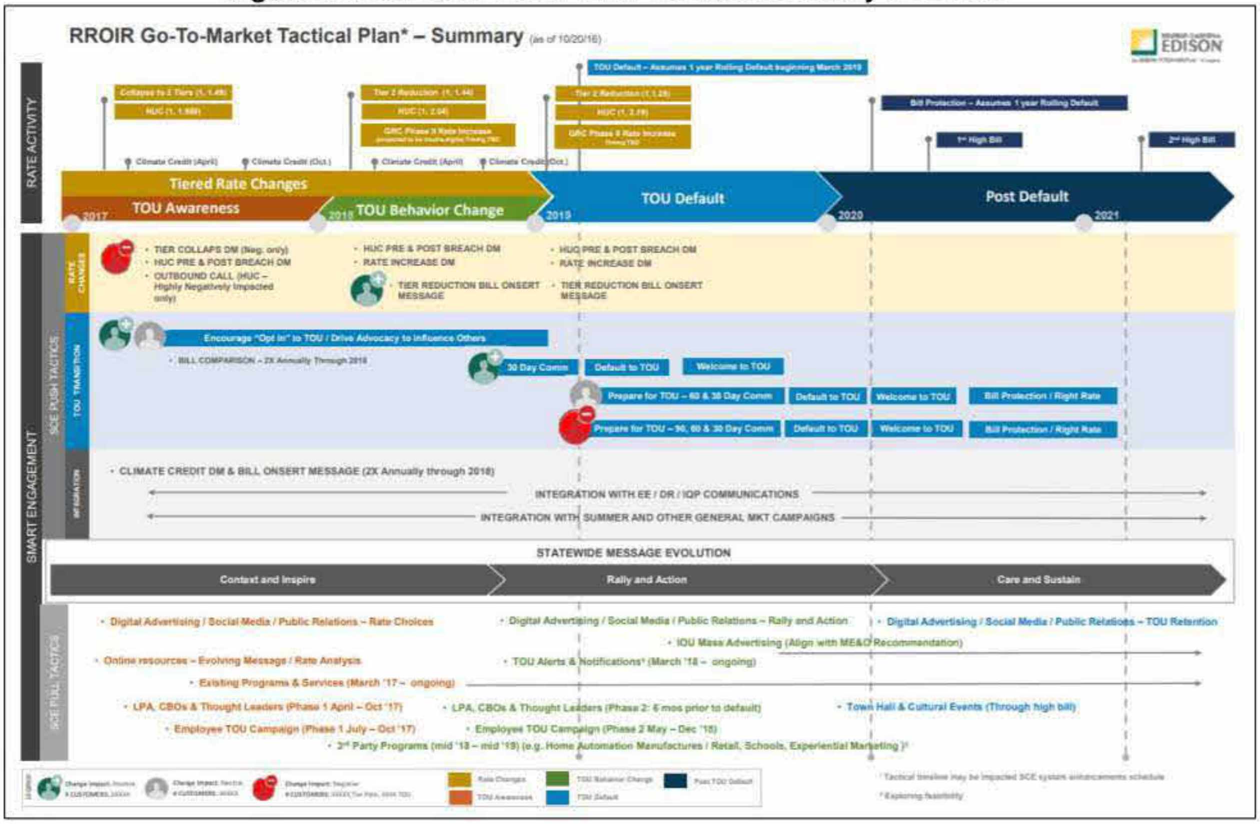


As shown, California's statewide rate reform effort was a global effort. Not only did it reform the existing tiered rates and establish a new "High Usage Charge," but it also embarked on the mass transition of customers from tiered rates to TOU rates.

However, even the comprehensive residential rates transformation for California's tiered and TOU rates does not convey the full complexity of SCE's specific rate transition. As illustrated in Figure 4 below, SCE's rate transition involved many more components and activities than shown in the statewide timeline.

[46] "2016-2019 Rate Reform & TOU Combined Research Report", December 2019, CPUC website, pg. 3.

Figure 4. SCE 2017-2021 Time of Use Summary Timeline[47]



Importantly, as Figure 4 shows, in addition to the tiered rate change and TOU transition, SCE also expected to incorporate a series of rate increases into its transition process, noted by two "GRC Phase II Rate Increase" callouts. Furthermore, while it is not noted in this graphic, SCE also sought and received approval to change its residential TOU periods at that time.[48,49] Thus, while SCE was embarking on the wide-ranging set of changes to its tiered rates and its transition toward mass market TOU rate adoption, SCE was also undertaking the two changes APS was undergoing: the adoption of a rate increase and a transition to new TOU periods.

SCE's modifications to tiered rates and its mass market transition to TOU rates were the main subject of its expansive ME&O transition. In other words, the rate change activities that APS focused its efforts and activities on were also occurring at SCE, however, they did not feature as prominently in SCE's customer education and outreach effort. Conversely, with APS they were the dominant feature. As discussed below, this important difference is one of several factors that suggest comparing the two transitions is inappropriate.

[47] SCE Advice Letter 3500-E, Appendix C: Communications Calendar
[48] SCE, A.17-06-030, June 30, 2017.
[49] CPUC D.18-11-027, December 7, 2018.

2.2.3 Critical Structural Differences between SCE and APS Rate Transitions

With complete and accurate descriptions of APS and SCE's residential rate transitions in place, Guidehouse will now proceed with its analysis of the critical structural differences between the two transitions and why these differences make the comparison inappropriate and potentially misleading. As described, the critical structural differences in the rate transitions result from fundamentally different:

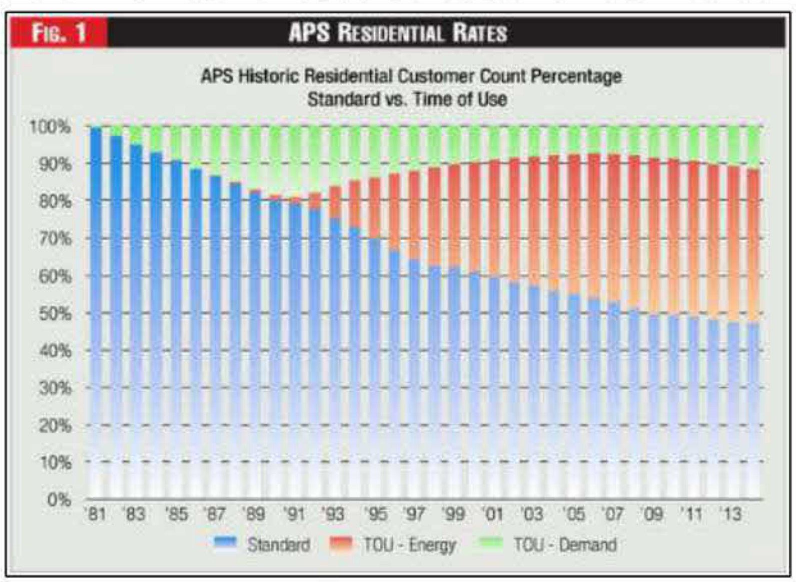
- Customer starting places
- Customer educational needs
- Policy objectives and Commission directives
- Customer education budget size and complexity

2.2.3.1 Fundamentally Different Customer Starting Places

In the years preceding their respective residential rate transitions, APS and SCE customers had significantly different experiences with the rates to which they were being transitioned. Combined with the nature of their transition – with APS defaulting its residential customers to their Most-Like Rate and SCE defaulting its customers from tiered rates to TOU rates – the difference in their respective starting places is foundational to understanding the stark and meaningful difference between the two transitions and the educational activities designed to support them.

As shown below in Figure 5, APS's residential customers have been on flat, TOU, and demand-based rates for decades, going all the way back to the late 1980s. By 2009, more than 50% of APS residential customers were either on a TOU energy or a TOU demand rate.

Figure 5. APS Historic Residential Customer Rate Breakdown[50]

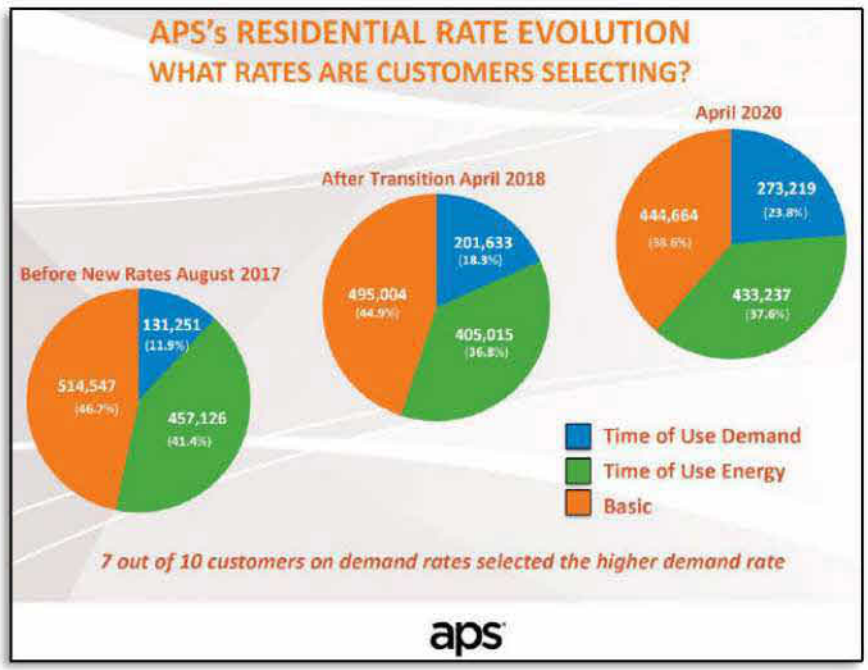


[50] "There and Back Again," Leland Snook and Meghan Grabel, Utility Fortnightly, November 2015, pg. 46-62.

As shown below in Figure 6, by August 2017, the number of APS's residential customers on TOU and demand rates had increased to roughly 53%. By the end of April 2018, at the end of the transition and after the new rate qualifications and requirement had been implemented, the number had increased to about 55%. Looking at the relatively small change in customer enrollment on these rates just before and just after the rate transition illustrates the results of moving customers to their Most-Like Rate, which is that most customers remained on a similar rate structure.

Two years later, in April 2020, other rate transition changes agreed to in the Settlement began to appear in the data – namely, new flat rate requirements and the "90-day trial" period for new customers to try a TOU rate before being able to move to a flat rate. By this point, with the basic flat rate for large customers (over 1,000 kWh/month of average usage) frozen to new customers and the 90 day trial period for new customers in place, the percentage of residential customers on TOU and demand rates grew to over 61%, a six percentage point increase over the period following the rate transition. While this represents an uptick in the transition away from flat basic service plans, looking back at the data from the 1980s shows that it is also a continuation of a multi-decade effort by APS and regulators.

Figure 6. APS Residential Rates Evolution – 2017 to 2020[51]



The starting point for the split of SCE's residential customers between tiered rates and TOU rates stands in stark contrast to APS's residential customers. SCE's second quarterly report on the Progress of Residential Rate Reform filed in February 2016 illustrates this difference. In this document, SCE reported having roughly 30,500 residential customers on TOU rates in 2015.

[51] "Arizona's Continued Adoption of More Advance Residential Rates", Leland Snook, EUCI Time of Use (TOU) and Residential Demand Charges Conference, May 2020.

This translates to approximately 0.7% of its roughly 4.4 million residential customers.[52] Below, Figure 7 details the breakdown of SCE's residential TOU customers.

Figure 7. SCE Residential TOU Enrollments – 2015

VIII. Opt-In Residential Time-of-Use Rate Enrollments

As of January 29, 2015 SCE has approximately 30,500 customers enrolled on optional TOU rates:

TOU Rate Option	Number of Customers
TOU-D Option A	5,603
TOU-D Option B	7,536
TOU-D-T	16,599
TOU-EV-1	774
Total	30,512

By comparison, between 2013 and 2017, APS had over 50% of its residential customers on TOU rates. With a residential population of over 1 million residential customers for APS, this percentage translates to more than 500,000 residential customers on TOU rates – more than 16 times as many customers as SCE.

Since 2015, however, SCE has substantially increased the number of residential customers on TOU rates through several major pilot programs and related marketing efforts. According to its most recent Progress of Residential Rate Reform filed in May 2020, SCE has over 467,000 residential customers on various types of TOU rates.[53] This transition has been accomplished through a carefully staged combination of an opt-in TOU pilot, a default TOU pilot, and marketing new optional TOU rates, with the target of the first wave of a full default TOU rollout beginning in October 2020.[54] A detailed breakdown of SCE's residential TOU enrollment across these various efforts is contained in Figure 8**,** below.

Figure 8. SCE Residential TOU Enrollments as of March 2020[55]

TOU Rates	Total TOU Enrollments 2019 - Q1	Total TOU Enrollments 2019 - Q2	Total TOU Enrollments 2019 - Q3	Total TOU Enrollments 2019 - Q4	Total TOU Enrollments 2020 - Q1	Opt-In TOU Enrollments 2019 - Q1	Opt-In TOU Enrollments 2019 - Q2	Opt-In TOU Enrollments 2019 - Q3	Opt-In TOU Enrollments 2019 - Q4	Opt-In TOU Enrollments 2020 - Q1
TOU-D Option-A	108,222	106,179	104,450	103,031	101,639	44,657	42,190	40,805	39,801	38,314
TOU-D Option-B	53,086	52,200	50,928	50,022	49,209	51,257	50,177	48,724	47,569	46,421
TOU-D-T	15,719	15,493	15,174	15,043	14,866	14,825	14,471	14,090	13,884	13,656
TOU-D-4	136,783	139,567	143,871	150,756	160,735	931	2,286	3,918	4,865	5,669
TOU-D-5	138,709	134,859	129,911	126,874	124,694	993	1,026	1,233	1,834	1,828
TOU-EV-1	897	898	895	891	876	896	897	894	890	875
TOU-D-PRIME	273	3,969	7,582	11,399	15,023	268	3,851	7,195	10,709	13,604
Total	453,689	453,165	452,811	458,016	467,042	113,827	114,898	116,859	119,552	120,367

Having described the paths APS and SCE followed to achieve their current level of residential TOU enrollments, the stark differences between how each utility arrived at their current state is now clear. Today, APS and SCE each have about 706,000 and 467,000 residential customers

[52] SCE's 2nd Quarterly Report on the Progress of Residential Rate Reform, February 1, 2016, pg. A-10.
[53] SCE's 19th Quarterly Report on the Progress of Residential Rate Reform, May 1, 2020, pg. A-10.
[54] Ibid, pg. A-8.
[55] Ibid, pg. A-10.

on TOU rates, respectively. While not equivalent in terms of percentage of total residential customers, these levels are within similar order of magnitude.

As shown, the difference is that APS took over 40 years to gradually move roughly 706,000 of its 1.1 million residential customers to TOU rates. In contrast, in less than five years, SCE went from 30,500 residential customers on TOU rates to 467,000 residential customers on TOU rates, and by February 2022, it will have defaulted roughly 2.4 million of its eligible residential customers from tiered rates to TOU rates.[56]

Thus, when each utility went about crafting their respective customer education and outreach plans, those plans were grounded in the rate experiences – the "starting place" – their customers had had to date. As this summary shows, those experiences were vastly different across the number of customers historically on TOU rates, the timeframe over which the transitions took place, and the scale of the change each utility sought to achieve.

2.2.3.2 Fundamentally Different Educational Needs

As described in the previous section, APS and SCE's residential customers were coming from starkly different starting points in terms of both their experience with TOU rates and the timeframe their utility had to educate them.

Ahead of the rate transition for which its 2017 CEOP was designed, APS had spent nearly 40 years gradually moving many of its residential customers to TOU rates. Consequently, with a transition based on defaulting customers to their Most-Like Rate, most customers were already prepared to adopt the changes to their rates because they were not dramatically different from what they had experienced in the past.

By comparison, as it started its transition to default TOU, SCE had very few customers with experience on TOU rates, and customers would have a relatively short period of time to become familiar with rates and pricing that were fundamentally different than what the vast majority of customers had experienced in the past.

When considering the different education needs of each utility's residential customers, APS's and SCE's respective starting points are critical. APS makes this point in its October 26, 2018 letter to Commissioner Dunn, stating (emphasis added):

> *"APS has a long history of providing information to customers about available service plan options and ways to save energy and reduce bills. Since the implementation of APS's initial experimental residential TOU rate in April of 1976, and its initial residential demand rate in April of 1981, the Company has encouraged its customers to take action to reduce energy usage.* ***Because of these decades of experience, the basic concept of TOU hours within an electric rate structure is well understood by APS customers****. In fact, Arizona continues to be one of the few states in which voluntary residential TOU and demand service plan options are available and widely adopted, and these service plan options have been widely accepted and adopted by customers throughout the Company's service territory."*[57]

As APS notes, these decades of past experience provide an important foundation for the rate transition, and while this experience alone was certainly not sufficient to serve all the education

[56] SCE's 16th Quarterly Report on the Progress of Residential Rate Reform, August 1, 2019, pg. A-13.
[57] Arizona Public Service Company, Response to Commissioner Dunn Request, Docket No. E-1345A-18-0002, October 26, 2018, https://docket.images.azcc.gov/0000193159.pdf, pg. 5 of 18.

and awareness needs to support customers in making choices about their new rate offerings, it did provide a strong basis of knowledge and understanding to build upon.

In reviewing ACC Decision No. 76295, the foundational understanding APS articulates above appears incorporated into the decision making. The resolution section of Decision No. 76295 that focuses on customer education does not contain any statements to rebut the fact that customers are already very familiar with the concept of TOU hours. This does not appear to be a point of contention. Instead, the resolution section centers its discussion on making customers aware of "which rate plan works best for their individual circumstances." In this discussion section, staff noted that:

> *"APS has indicated that it is committed to making sure that customers are aware of their options, and that it will notify customers through a variety of different channels and encourage customers to choose the rate plan that works best for them…The Settlement Agreement makes significant changes to the existing rate plans. We find that it is in the public's interest to have adequate notice in a timely manner so customers can evaluate the available plans before the deadline."*[58]

As shown by these statements, APS's education efforts centered around the idea of educating customers regarding their upcoming rate choices, not around a basic understanding of TOU rates. This distinction is a critical one and, as shown below, is the opposite of what captures the most attention in CPUC's decision on California's ME&O plans.

Instead of being primarily focused on making sure customers understand their rate options, SCE's rate plan had to focus on achieving a level of understanding APS's customers already had; namely, understanding the basic concept of TOU rates. In its decision ordering the California IOUs to embark upon their ME&O planning, the CPUC cites research in its decision that "customer awareness of existing rates is modest at best" for California's residential customers. Diving further into California residential customers' lack of understanding, the CPUC elaborates by noting that the research showed:

> *"19% [of representative residential customers from the IOUs' populations] responded that they were currently on a TOU rate plan, however according to IOU data, as of April 2015, only 3.4% of PG&E's residential customers are on TOU rates, while SCE and SDG&E have 0.52% and 0.6% of residential customers on TOU rates respectively. According to the study, '75% of customers have tried to save money by shifting their electricity use' and 'despite most customers knowing they are not on a TOU rate, many believe they have saved money by shifting.'"*[59]

As this research indicates, ahead of the state's transition to default TOU rates, California's residential customers lacked a firm understanding of their current rate structures, and they were confused about whether or not their existing service plans were time-based; accordingly, they were also confused about appropriate strategies to save money. Thus, closing the knowledge gap regarding customers' basic understanding of their rate structure was a key educational hurdle for California's ME&O plans to address.

As the analysis here has shown, APS and SCE's residential customers started their rate transitions with different levels of understanding and, based on the focus of their respective rate transitions, each utility's customers required different educational materials.

[58] ACC Decision No. 76295, pg. 54.
[59] CPUC D.15-07-001, pg. 29.

2.2.3.3 Fundamentally Different Policy Objectives and Commission Directives

An additional reason why comparing APS and SCE's customer outreach programs is flawed is because the respective programs were crafted to respond to fundamentally different policy objectives and Commission directives. Whereas SCE's ME&O plan has its genesis in a rulemaking and set of decisions centered solely around the comprehensive reform of residential rates, APS's CEOP plan came out of one narrow section of a broad rate case application spanning multiple operational areas.

In the procedural history section of ACC Decision No. 76295, staff describe the high-level scope of APS's application as follows:

> *"In the Application, which is based on a test year ending December 31, 2015, APS sought a $165.9 million net increase in base rates, changes in some of its adjustor mechanisms, establishment of a mandatory new three-part demand-based rate design for residential and small commercial rate design, reduction of on-peak time-of-use hours, and grandfathering of existing solar customers while modifying net metering arrangements for new solar customers."*[60]

The decision covers topics from cost of capital to property tax rate deferral to rate design for low-income customers. The section of the decision focused on Staff's resolution of issues related to the CEOP are covered in roughly two and half pages.[61] With regard to significant changes to residential rates, the decision's orders do not promulgate new policy changes and, in the order it requires APS to file its CEOP, it does not specify that APS should include any educational or outreach tracking metrics. Furthermore, in the settlement agreement itself, the education plan is only referenced twice: Section 1.5L (pg. 7 of 32) and Section 27.1 (pg. 24 of 32). These findings suggest that while customer education was an important area of consideration by the ACC, it was not one of the decision's main focal points.

In contrast to the decision ordering APS to file it CEOP, the CPUC's Order Instituting Rulemaking on Residential Rate Reform (Rulemaking 12-06-013) is, relatively speaking, narrower in scope and focused purely on topics related to residential rate design and policy. In the background section of D.15-07-001 on residential rate reform and transition to TOU rates, the CPUC articulate the focus of the rulemaking guiding D.15-07-001 and all other residential rate reform decision as follows (emphasis added):

> *"Rulemaking (R.) 12-06-013 will not change the total revenue requirement. It will also not change the revenue allocation between customer classes, or the amount of revenue requirement for which the residential class is responsible.* ***Rather, this proceeding will change the rate design rules for residential customers*** *that make up the entire slice of revenue requirement pie for which they are already responsible…Our review in the* ***instant proceeding is limited to considering the appropriate rate design for the residential class****"*[62]

On the topic of customer understanding, the CPUC stated plainly that (emphasis added) "we agree that residential customer understanding of rates should be ***a key objective of this proceeding***."[63] To that end, the CPUC ordered the IOUs to "work with other parties to implement a working group (ME&O Working Group) to examine ME&O for residential rate changes generally, and how ME&O for rate changes interacts with other residential programs."[64]

[60] ACC Decision No. 76295, pg. 4.
[61] Ibid, pg. 53-55.
[62] CPUC D.15-07-001, pg. 7-8.
[63] Ibid, p. 31.
[64] CPUC D.15-07-001, p. 299, 336 at Ordering Paragraph 14.

In D.15-07-001, the CPUC notes several key parties to be included in the ME&O working group, including Energy Division Staff and the Office of Ratepayer Advocates, and it orders the IOUs to "initiate the process of forming a working group to address the issues regarding marketing, education and outreach (ME&O Working Group)" within 30 days of the decision.[65] Thus, from the outset, the CPUC communicated the centrality of customer education and the importance of collaborative structures between stakeholders, Commission staff, and utilities in architecting the approach to customer education.

Upon establishing the ME&O working group, SCE then partnered with the other IOUs and stakeholders to develop and gain CPUC approval for the performance tracking metrics presented in Figure 9 below. As with establishment of the ME&O working group, the CPUC directed the IOUs to collaborate with the working group and outside experts to develop these metrics.[66]

Figure 9. SCE's CPUC Approved ME&O Tracking Metrics[67]

The approved primary metrics are as follows:

Metric #	Metric	Goal vs. Tracking
1	Customers are aware that there are rate plans that may help them mitigate energy expenditures	Goal
2	Customers know where to get more information about how to manage their electricity use	Goal
3	Customers understand how energy use can impact their bills	Goal
4	Customers understand the benefits of lowering their electricity use and of shifting their electricity use to non-peak hours	Goal
5	Customers are aware of rebates, energy efficiency programs, demand response programs, energy management technologies and tips that are offered by the utility that can help them manage their electricity bill	Goal
6	Customers feel they were provided useful information explaining their bills	Goal
8	Customers were provided with information and services to help reduce their energy bill	Tracking
19	% of customers on opt-in TOU rates	Tracking

Following the approval of its ME&O metrics, SCE was required to report on progress against these metrics in its quarterly "Progress of Residential Rate Reform" filing.

As shown, Arizona and California regulators promulgated meaningfully different policy objectives and directives in the Commission orders that guided APS's and SCE's respective rate transition education plans. The differences in these objectives and directives logically led to plans by APS and SCE that targeted differing educational outcomes and that were formed by very different processes.

[65] Ibid, pg. 336 at Ordering Paragraph 14.
[66] CPUC Resolution E-4895, pg. 41.
[67] Ibid, pg. 32.

2.2.3.4 Fundamentally Different Budget Size and Complexity

As described in the previous three sections of Guidehouse's analysis, the APS and SCE customer education and outreach plans for their respective rate transitions were shaped by different customer starting points, different customer educational needs, and different policy objectives and Commission directives. These differences are manifest in the size and scope of each utility's authorized educational budget and highlight once more the structural differences between the APS and SCE rate transition educational plans.

In its seventh quarterly report on the "Progress of Residential Rate Reform" from May 2017, SCE projected its ME&O budget for 2017 to 2020 at approximately $70 million. The high-level budget breakdown, shown in Figure 10, conveys a wide-ranging set of activities designed to support multiple objectives associated with the rate transition. The key items listed in SCE's ME&O plan address technical and operational activities, customer research, external community engagement, funding to support both SCE's default TOU pilot and full default TOU rollout, and a significant budget on mass media TOU market and education (approximately $30 million from 2017 to 2020).

Figure 10. SCE's Estimated Budget for ME&O from 2017 to 2020, dated May 1, 2017[68,69]

SCE's RROIR ME&O Budget Estimates for years 2017 - 2020						
Tactic	2017 Budget	2017 Budget Q1 Actuals	2017 Budget Q2 Actuals	2018 Budget	2019 Budget	2020 Budget
TOU Marketing & Education (Mass Media)	$6,117,600	($16,591)	$81,147	$11,051,600	$4,546,100	$8,142,400
Bill Comparisons	$1,500,000	$13,642	$183,037	$2,600,000	$2,600,000	$2,600,000
Default TOU Pilot	$213,592	$6,118	$54,718	$2,456,058	$213,675	$0
Default TOU	$859,272	$0	$0	$7,796,995	$4,552,835	$10,278,798
Web Development (Inclusive of all activities)	$82,800	$20,580	$188	$35,080	$37,588	$41,347
Contact Center	$123,000	$0	$0	$0	$0	$0
Customer Research	$250,000	$18,518	$46,520	$250,000	$300,000	$300,000
Outreach (CBO's, Public Relations, Employees)	$229,031	$0	$0	$247,000	$247,000	$247,000
Marketing Automation	$268,000	$0	$0	$186,625	$55,000	$40,000
High Usage Charge	$770,000	$4,944	$9,684	$750,000	$750,000	$750,000
Total	**$10,413,295**	**$47,211**	**$375,295**	**$25,373,358**	**$13,302,198**	**$22,399,545**

By comparison, the budget for APS's CEOP is understandably narrower in scope and smaller in size. In terms of size, the $5 million of authorized funding APS received is less than one-tenth the size of SCE's. Even when compared to the ME&O plan put forth by SDG&E, which has a residential customer population closer in size to APS's population (1.4 million for SDG&E), the APS budget is still relatively small. In its "Progress of Residential Rate Reform" from May 2017, SDG&E reported its 2017 to 2019 budget at more than $19 million, or about four times as large

[68] SCE's 7th Quarterly Report on the Progress of Residential Rate Reform, May 1, 2017, pg. A-15.
[69] Note: As cited above, the budget table presented here is drawn from SCE's 7th quarterly PRRR. We have referenced this budget because its total of about $70 million and four year time period aligned with the one described in footnote three of the Alexander Report, which described a "multiyear education plan included a budget that totaled almost $70 million over a four year period." In an effort to conduct an "apples-to-apples" comparison, we have cited the budget we believe is the closet match. Another logical budget to reference would have been the one in Advice Letter 3500-E from SCE's Marketing, Education and Outreach Plan for Residential Default to TOU Rates. This budget is found on page 70 of CPUC Resolution E-4895, which approves 3500-E. The budget from the advice letter totals roughly $40 million, which indicated it was not the right budget to use for this comparison.

as APS's CEOP budget.[70] This serves as another example of the differences between APS's plan and the various California ME&O plans.

As indicated in the breakout of CEOP outreach funding presented in Figure 11 below, the relative scope of the CEOP activities are narrow compared to SCE's ME&O plan.

Figure 11. APS CEOP Budget Breakdown[71]

Funding Category	Amount
Customer Tools	$1,361,503
Materials and Printing	1,310,215
Rate Analysis	1,180,080
Mass Media	661,163[8]
Community Events	6,012
System Integration	310,256
Non-Residential	9,335
Outside Services	52,465
TOTAL	**$4,891,029**

Like SCE, APS's activities focused on customer tools, mass media, and various operational activities. However, APS's plan did not focus on numerous activities that were focal to SCE's approach, particularly default TOU outreach, which alone was more than $10 million of SCE's budget.

By design, the plans are funded by widely different budget amounts and aim to achieve different goals, which are driven by differing historical customer experiences, educational needs, and policy objectives and Commission directives.

[70] SDG&E's 7th Quarterly Report on the Progress of Residential Rate Reform, May 1, 2017, pg. 6.
[71] APS Docket No. E-1345A-18-0002, Formal Complaint of Stacey Champion, Response to Commissioner Dunn Request, October 26, 2018, pg. 14.

3.0 Utility Education & Outreach Best Practices

In this chapter, Guidehouse first provides important context for utility ME&O plans and a broader overview of education and outreach best practices. Notably, utility ME&O plans vary widely in scope and unique regulatory requirements. Furthermore, given the nascent stage of digital tools, big data, and rate modernization efforts, utility best practices are evolving and not necessarily well-established in the area of customer rate transitions.

Guidehouse conducted an independent review of APS's 2017 CEOP and its implementation compared to industry best practices and industry norms by leveraging a range of secondary sources and our in-house expertise. The sources referenced include rate transition plans, multi-utility studies on recent rate transitions and related marketing plans, other utility program outreach campaigns, and behavioral science studies. This chapter describes how the CEOP and its implementation compare to (1) general utility best practices and industry norms and (2) best practices from behavioral science.

3.1 General Utility Best Practices

Guidehouse used a two-step process for reviewing the CEOP against general utility best practices: (1) identify best practices related to the CEOP's goals and (2) compare the CEOP plan and implementation to-date to those best practices and to common utility practices (or industry norms). The scope focuses on best practices that relate to the CEOP's goals because utility practices vary widely based on unique regulatory mandates, internal capabilities, budgets, and other factors. The sections below detail the outcome of this assessment.

3.1.1 Best Practice Overview

Given the importance of contextualizing best practices, Guidehouse limited the best practices to those that align directly with the APS's 2017 CEOP stated goals:

1. Drive awareness of new rate structures and best rate choices.
2. Acknowledge customer interest and answer customer questions.
3. Educate customers on opportunities to save through core message of "shift, stagger, save" and DSM programs.
4. Encourage customers to "engage" with electric usage and learn how it can affect their bill.
5. Increase customer adoption of tools and resources to facilitate electric usage awareness and control.

With these goals in mind, Guidehouse developed a list of best practices from nine different secondary sources. These sources include utility documentation for rate transitions, meta-studies on utility rate transitions, and other utility program marketing and outreach efforts. The review focused on large utilities that have had recent rate transitions and studies with multiple utilities from industry-standard sources, such as the US Department of Energy (DOE). Utilities in the materials reviewed include the California investor-owned utilities (IOUs), Sacramento Utility Municipal District (SMUD), DTE Electric Company, Hawaiian Electric (HECO), AEP Ohio, and the Salt River Project (SRP), amongst others.

Guidehouse synthesized this research to develop a list of best practices across five topic areas: (1) communication planning, (2) communication methods, (3) resources and tools, (4) message content, and (5) metrics and reporting. Figure 12. below provides an overview of each of these topic areas.

Figure 12. Best Practice Topic Area Overview

Communication Planning (CP)	Communication Methods (CM)	Message Content (MC)	Resources & Tools (RT)	Metrics & Reporting (MR)
• Practices related to preparing a marketing and outreach plan that meets stated objectives	• Channels for maximizing communication opportunities	• Information and types of communication provided to educate customers about rate changes	• Materials for customers to learn more about new rates or programs	• Methods for evaluating the program

Source: Guidehouse

Table 8 lists the best practices identified by Guidehouse by topic area. Importantly, these practices reflect the research available at the time of writing this report.

Table 8. General Utility Best Practices

Number	Name*	Description	Industry Norm	Best Practice
Topic & Practice ID	**Short name of best practice**	**Detailed description of best practice**	**Common practices / typical level of effort observed among utilities, based on secondary research**	**Level of effort that meets best practice, based on secondary research and Guidehouse expertise**
CP1	Conduct market research [1,2]	Analyze customer needs and perceptions via surveys and focus groups, to inform marketing and communication strategy, messaging and approaches	**Somewhat common** to conduct, although some utilities do not use market research due to budget and skill constraints or limitations.	**Consistent** use of fielding of market research to test messaging and gauge customer interests for each new rate offered.
CP2	Define message strategy by customer segment [10]	Develop customized messages tailored to specific customer segments (e.g., income, ethnicity, target market)	**Rare** to implement customized messages.	**Evaluate use** of customized messages for new, important customer-wide initiatives.
CP3	Identify and monitor key communication touchpoints [1, 5, 6, 8, 9]	Plan to send notifications (e.g., end of bill, high use alert, peak use season) and follow ups (e.g., you've been on this rate for one year – don't forget) on certain milestones. Monitor these communications to maintain effective relationships.	**Common** integration of notifications in the communication plan, but quality of execution is varied (e.g., utility/software issues).	**Consistent** integration of notifications in the communication plan and implementation of protocols for quality assurance of plan.
CP4	Optimize frequency and synchronize with other channels and programs [3,5]	Reduce communication fatigue by coordinating communications across the utility and enhance messaging opportunities	**Common** to coordinate frequency and program messaging across the utility.	**Consistent** coordination of frequency of outreach and messaging across the utility.
CP5	Prepare and train customer representatives and other employees to answer questions [1, 3]	Ensure customer service representatives can track customer cases over time (e.g., whether customer has transitioned to a new rate or has high bills) and all related staff are prepared to answer customer questions.	**Near universal** to train call center representatives, including procedures for when to engage more knowledgeable staff. Rare to train other utility staff.	**Consistent** all employee and related vendor training for important, new customer-wide initiatives.
CP6	Conduct soft launches [1]	Plan to have a smaller pre-launch and allow enough time to test and adjust messages, if needed	**Somewhat rare** to implement soft launches.	**Consistent incorporation of** soft launches with at least two-three weeks in before hard launch to adjust messages or implementation.
CM1	Use a variety of traditional and digital marketing outlets [1, 8, 9]	Implement messages via radio, newspaper ads, doorhangers, letters, business reply cards, bill inserts, phone calls, social media, emails, texts, videos, dedicated web portals, and smart phone apps to reach a broad group of customers	**Near universal** implementation of traditional and digital outlets.	**Consistent** use of traditional and digital marketing outlets to reach the broadest group of customers.

Number	Name*	Description	Industry Norm	Best Practice
CM2	Employ community-based outreach (CBO) [1, 11]	Leverage organizations, such as Chamber of Commerce or neighborhood associations, within the community to reach customers	**Rare** to use CBO for larger utilities, like APS.	**Evaluate** use of CBO for large initiatives. A 2012 MIT study noted that CBO implementation success varies widely and is costlier to implement, therefore utilities should evaluate the costs and benefits prior to implementing. [72]
MC1	Align rate transition to broader (EE or DSM) program marketing or strategic initiatives [3]	Implement rate transition as part of a broader strategic initiative to help customers understand how rates relate to these efforts (e.g., energy efficiency, demand side management, climate).	**Unclear how common** it is to align rate transition or broader program initiatives.	**Consistent** alignment of rate transition to broader program or strategic initiatives.
MC2	Set realistic scenarios about how behavioral choices influence bill impacts [1, 3, 6, 7]	Show customers different use cases and how the rates may impact customers' lifestyles to provide realistic scenarios.	**Common** to provide customer examples (e.g., case studies or use cases) to show how rates may impact lifestyles and bills.	**Consistent** use of customer examples for the transition to time differentiated rates.
MC3	Ensure accuracy of bill and savings estimates in communications and tools (e.g., bill calculators) [1, 3]	Check billing estimates and analytics to ensure that utility communicates correct information to customers.	**Somewhat Rare** to have inaccuracies in billing or savings estimates.**	**Consistent** provision of accurate information.
RT1	Provide bill or rate comparisons (pro forma billing) / bill calculators [1]	Illustrate how new rates or programs will impact customers' bills with information and tools comparing or providing examples of bill savings	**Somewhat rare** to provide rate/ bill calculators and/or comparisons.	**Consistent** use of rate/bill calculator and comparisons with actual customer usage (rather than estimates).
RT2	Establish comprehensive customer portal [1, 3, 8]	Develop web and/or app portal with resources rates available, ideas on how to manage energy, assistance programs and frequently asked questions (FAQ).	**Near universal** to develop dedicated customer website or portal to engage customers.	**Consistent** use of dedicated customer website or portal that is regularly updated with relevant information.
RT3	Provide materials to engage customers [2,6]	Send welcome kits or develop games about energy savings, so customers can interact with the materials.	**Somewhat rare** to provide materials directly to customers to engage with the topic.	**Consistent** use of interactive customer materials for important, new customer-wide initiatives.

[72] McEwen, Brendan. Community Based Outreach Strategies in Residential Energy Upgrade Programs. May 22, 2012. MIT Department of Urban Studies and Planning. http://web.mit.edu/energy-efficiency/docs/theses/mcewen_thesis.pdf.

Number	Name*	Description	Industry Norm	Best Practice
RT4	Implement bill guarantees [1, 2]	Allow some or all customers to pay bills based on previous rates (if lower than new rate) for a defined period of time (e.g., 6-12 months) to lower risk of transition.	**Somewhat rare** to provide safety nets, such as bill guarantees.	**Consistent** use of bill guarantees for universal transition to time differentiated rates.
MR1	Establish education and outreach goals and success criteria [1, 2, 7, 9]	Plan to track metrics against success criteria over time.	**Somewhat common** to define success criteria and track metrics in comparison.	**Consistent** comprehensive evaluation of outreach and education effort.
MR2	Analyze marketing metrics [9]	Evaluate marketing effectiveness through click-throughs, message opens, and engagement surveys.	**Common** to track marketing metrics.	**Consistent** tracking of marketing metrics.
MR3	Analyze program-related metrics [1,7]	Evaluate impact, process, and outcome of education and outreach campaign. Metrics may include customer awareness and knowledge, behaviors, barriers to action, enrollment rates, peak demand reduction, bill savings, and customer satisfaction.	**Varies from Rare to Common** to track program-related metrics. It is **Rare** in cases of rate transitions to similar rates but **Common** in cases of wholesale transitions to time-differentiated rates.**	**Consistent** tracking of program-related metrics. (Industry seems to be moving in this direction).

Source: Guidehouse
**Numbers in this column correspond to the sources in Appendix B.*
***Guidehouse used its expertise to come to this conclusion due to the lack of secondary sources available to verify.*

3.1.2 Review of the 2017 CEOP & Implementation

Utilities are moving towards modernizing their rates, leveraging digital tools and advanced data capabilities to enhance customer experiences, including education and outreach. Utilities are proceeding cautiously during this transition and are often hindered by technical challenges and lack of understanding of best practice. Furthermore, regulatory mandates and stated objectives vary by utility. These facts have resulted in a range of practices related to customer education and outreach, which often deviate from best practice for a range of reasons.

Recent customer and utility surveys confirm that industry norms vary from best practice. For example, a 2019 Smart Energy Consumer Collaborative (SECC) study found that almost half of residential customers (out of a survey of 1,500 customers) are unsure what electric rate plan they have.[73] Likewise, a 2017 UtilityDive and NTC study found that only 7% of utilities believe their programs are "great" and 55% believe they are "average" or "poor" at educating residential customers and motivating them to take actions (out of a survey of 187 industry professionals).[74] These examples illustrate that industry norms do not necessarily equate to best practice and that there is considerable room for improvement for utility education programs in general.

Due to the variance in practices, Guidehouse reviewed APS's CEOP and its implementation and compared them to industry norms and best practice, as evidenced by the literature reviewed and the research team's expertise. This assessment uses a scale with four discrete grades:

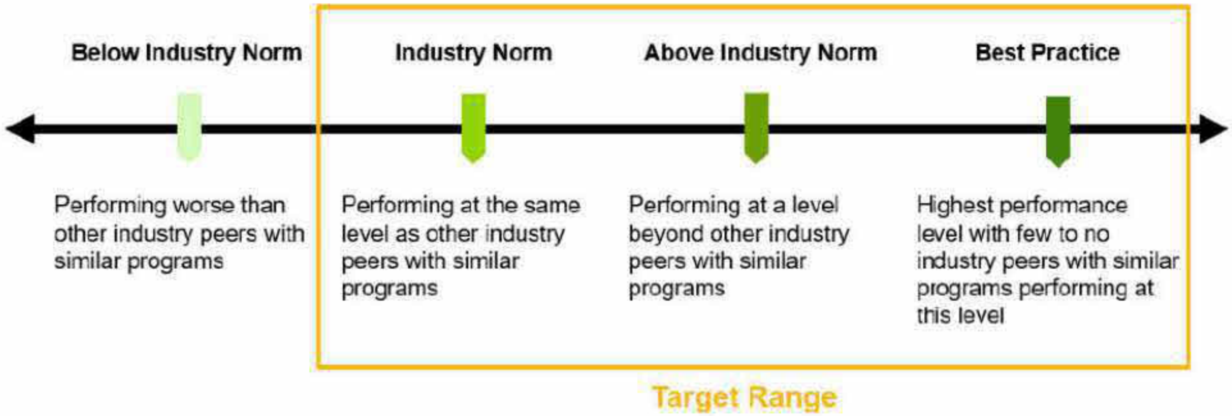
1. Below industry norm
2. At industry norm
3. Above industry norm
4. Best practice

The Guidehouse assessment does not represent the same scope as a full, comprehensive evaluation of the CEOP. The assessment was limited to secondary research based on sources available and information provided to Guidehouse as part of this engagement. In particular, the comparisons are limited by the lack of information from other utilities that have undergone similar rate transitions. A full evaluation would also include a more thorough review of all of APS's implementation activities and materials to-date.

Ideally, APS's CEOP and its implementation would fall between industry norm and best practice, moving towards best practice to the extent feasible and applicable to its scope, budget, and objectives. Figure 13. below outlines the scale used to measure APS's CEOP and plan implementation performance.

[73] Smart Energy Consumer Collaborative (SECC), Rate Design: What Do Consumers Want and Need Report, September 25, 2019, https://smartenergycc.org/rate-design-what-do-consumers-want-and-need/.
[74] DiveBrandStudio and NTC, 2017 Utility Residential Customer Education Survey, 2017, https://s3.amazonaws.com/ntcpardot/2017/utility-Q4/NTC_Survey_2017_draft+3.pdf.

Figure 13. Utility Education & Outreach Performance Scale



Source: Guidehouse

Note: Guidehouse uses "industry peers with similar programs" in this graphic and chapter to refer to large utilities implementing a rate transition that involves a partial or complete transition to time differentiated rates.

As shown above, the scale includes a range of acceptable practices, based on the performance of industry peers with similar programs. Table 9 below summarizes the assessment of APS's CEOP and its implementation on this scale.

Table 9. APS Performance for Outreach and Education Best Practices

Topic Area & Practices	Guidehouse Review & Rationale
Communication Planning • Conduct market research • Define message strategy by customer segment • Identify communication touchpoints • Optimize frequency and synchronize with other channels/programs • Prepare and train customer reps • Conduct soft launches	**Performed at Industry Norm** – APS implemented similar planning techniques to industry peers with similar programs, including identifying communication touchpoints, training call center staff, and coordinating with at least one other program (e.g., DSM). APS leveraged extensive historical customer research but did not conduct new customer research, which puts them on par with industry norm. The secondary sources Guidehouse referenced noted that market research practices were mixed, as some industry peers with similar programs conduct regular market research and others do not conduct any market research due to budget and staff constraints.
Communication Methods • Use a variety of traditional and digital marketing outlets • Employ community-based outreach (CBO), if appropriate	**Performed at Best Practice** – APS implemented a wide range and used a significant volume of traditional and digital marketing materials through multiple channels, including CBO in alignment with best practice. The Overland Report and the APS Response to Commissioner Dunn Letter confirmed this finding.
Message Content • Align rate transition and broader program marketing messages (e.g., DSM) • Set realistic bill savings expectations (for time variant rates) • Ensure bill savings and data analytics accuracy in communications and tools (e.g., bill calculators)	**Performed at Industry Norm** – APS aligned its rate transition customer education with broader program marketing, which is best practice. However, there was some evidence that customers did not understand APS's messaging on the concept of "saving" — specifically, whether simply moving to a new rate plan would save them money, as opposed to saving money by modifying their electricity consumption behaviors (in accordance with the *Shift, Stagger, Save* message).

Topic Area & Practices	Guidehouse Review & Rationale
	APS also had an error in its rate comparison tool from February 2019 to November 2019.[75] Although not a desirable customer experience, a US DOE study shows that industry peers with similar programs often experience issues related to messaging and technology implementation like APS.[76]
Resources & Tools • Provide rate or bill comparisons / calculators • Establish comprehensive customer portal • Use materials that engage customers • Implement bill guarantees, if budget allows and appropriate for scope of rate transition	**Performed at Best Practice** – APS provided a wide range of materials to educate and engage customers in alignment with best practice. In many cases, APS provided more materials than most industry peers with similar programs studied. For example, APS provided customers with welcome kits and the rate comparison tool, which are resources and tools that many other peers did not offer. The Overland Report also confirmed this finding.
Metrics & Reporting • Establish education and outreach goals (in alignment with industry peers with similar programs) and success criteria (in alignment with best practice) • Analyze marketing metrics • Analyze program-related metrics (in alignment with industry trends)	**Performed at Industry Norm** – APS established education and outreach goals and analyzed marketing metrics in alignment with other utilities. However, APS did not articulate success criteria, nor did it establish *program*-related metrics for the CEOP and its implementation. Although best practice, Guidehouse's research shows that implementation of these practices is mixed and therefore, APS is still in alignment with industry norm.

As shown above, APS performed at industry norm or best practice in all five of the topic areas. APS performed particularly well in the Communication Methods and Resources and Tools category compared to industry peers with similar programs. This performance has to do with the fact that APS provided a wide range of materials and resources for customers to engage with rate transition concepts.

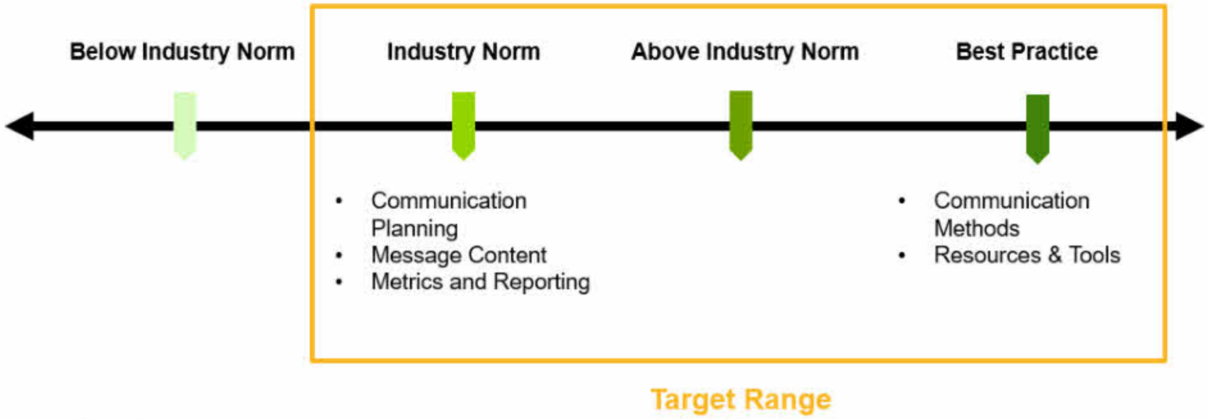
Although APS did not perform best practice in the Communication Planning, Message Content, and Metrics & Reporting categories, APS performed similarly to the industry peers cited in the sources reviewed. In some cases, the research provided a mixed picture of utility practices. For example, the DOE report includes an entire section dedicated to issues and lessons learned with implementing new technology (e.g., bill calculators and rate comparison tools) for rate transitions. The extent to which practices vary greatly by utility helps demonstrate how APS performed within the industry norm in several areas.

Figure 14 summarizes APS's performance in each category.

[75] APS has since provided refund checks to 12,971 affected customers, or approximately $1,065,000 in total refunds, which includes a $25 inconvenience credit. Additionally, based on an approach developed by a Commission consultant with which the Company does not necessarily agree, APS has also refunded an additional 3,787 customers $468,748, which includes a $25 inconvenience credit.

[76] U.S. Department of Energy, Experiences from the Consumer Behavior Studies on Engaging Customers, September 2014, https://www.energy.gov/sites/prod/files/2014/11/f19/SG-CustEngagement-Sept2014.pdf.

Figure 14. APS Performance for Education & Outreach Practices



Source: Guidehouse

Importantly, the market appears to be moving towards a more programmatic approach to rates implementation – focusing on continuous process improvement – thus redefining what is considered best practice for the Metrics & Reporting category. Guidehouse recommends that APS begin approaching its rates from this perspective by evaluating performance against strategic objectives and focusing on continuous improvement, especially for the topic areas above.

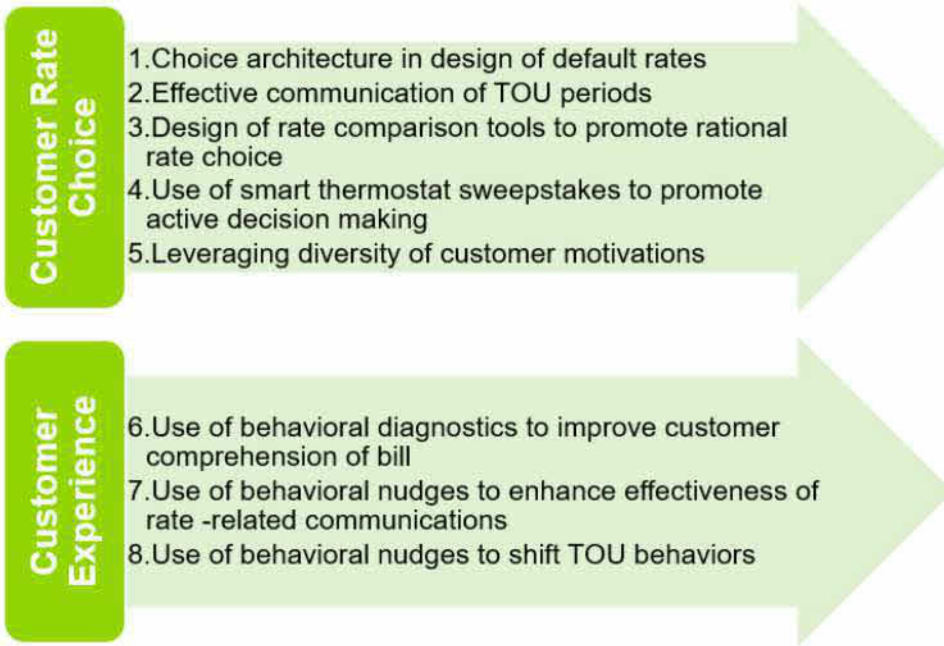
3.2 Behavioral Science Best Practices

Guidehouse used the same two-step process for evaluating CEOP activities against behavioral science best practices: (1) identify relevant behavioral science best practices research and findings and (2) compare APS's education and outreach activities to those best practices.

Guidehouse identified a set of eight behavioral science best practices in two categories, derived from a variety of behavioral research studies including utility-specific studies and more general behavioral science studies. These sources include utility research and documentation associated with rate transitions and rate pilots, utility studies of the effectiveness of behavioral strategies for encouraging energy savings in DSM programs, and other behavioral science studies.

The eight behavioral science best practice areas are summarized in Figure 15, below. In the following descriptions, each best practice area is labeled as a strength or as an opportunity for improvement for APS. This review is summarized at the end of the section.

Figure 15. Behavioral Best Practice Category Overview



Source: Guidehouse

3.2.1 Customer Rate Choice

1. Using choice architecture to address status quo bias through default options (strength)

When faced with a choice that offers a default option, most people go with the default option – a phenomenon known as a status quo bias. Given the tendency for status quo bias, the best utility programs actively create a customer choice architecture that designs default options so as to maximize the benefit to customers. The need to account for status quo bias begs the question "Why do most people passively choose the default option when given a choice?" Status quo bias can best be described as an emotional preference for the current situation over an alternative due to the required investment of emotional or psychological energy necessary to choose an alternative.[77]

Given the preference for the status quo, programs that are unaware of this bias may incorrectly interpret people's failure to actively make a choice as an indication of low levels of awareness, irrational behavior or poor program execution. The likelihood of this misinterpretation may be even more pronounced if choosing the default results in a sub-optimal outcome from the observer's perspective. For individuals faced with a decision, the influence of status quo bias may be even more pronounced when the difference between choices is small or when the

[77] Samuelson, W., & Zeckhauser, R. J. (1988). "Status quo bias in decision making". *Journal of Risk and Uncertainty, 1*, 7-59.

default option (what happens if/when the individual fails to make a choice) is perceived as either satisfactory or optimal.

Because status quo bias is so powerful, it is important for program designers to thoughtfully and intentionally establish the customer choice architecture with the goal of maximizing beneficial outcomes for the majority and to also recognize that "there is no such thing as a 'neutral' design."[78] By using choice architecture, designers work to intentionally "influence choices (or outcomes) in a way that will make choosers better off, *as judged by the choosers themselves*." "Nudges" are the tools that designers use to craft effective choice architectures.

The Guidehouse review of the rate transition process found that the APS rate design choice architecture was well structured. While customers were provided with several rate choices, customers who failed to choose a new rate were defaulted into the Most-Like Rate. The choice to default customers into the Most-Like Rate is well aligned with the reality that a large proportion of people tend to be averse to change and that many APS customers may have previously selected their legacy rate, implying a preference for that rate, regardless of whether the selected rate was the most economical choice.

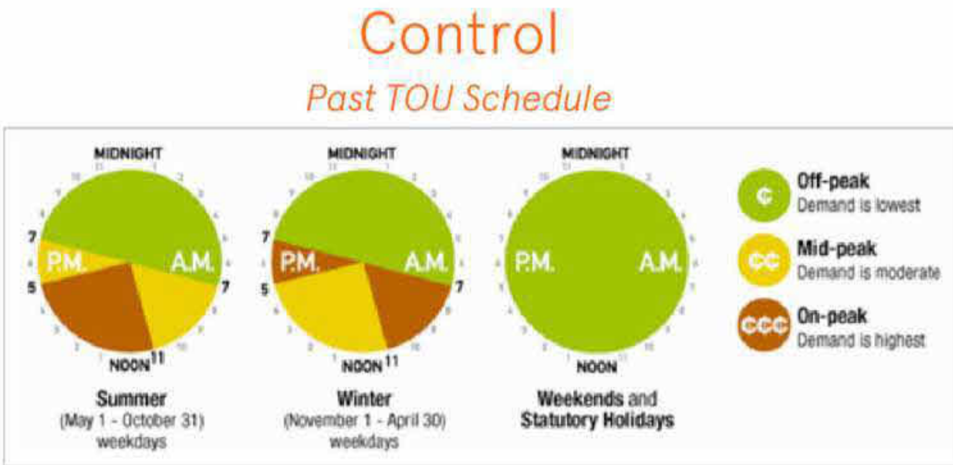
2. Communicating savings periods in TOU rates (opportunity for improvement)

Behavioral science research on customer comprehension of new rate structures can maximize that comprehension and help customers to perform better on the new rate. Customers who use TOU rates for the first time often encounter difficulties understanding time-based rates if savings periods are not clearly communicated.

According to one behavioral research study, utility customers face psychological barriers that can impede the comprehensibility of graphic illustrations of time-based rate structures. This research was performed in Ontario to better understand why only 23% of customers correctly understood different elements of TOU pricing. The research assessed customer comprehension of linear versus nonlinear graphical presentations of rate structures and found that "a circular depiction of time is *incongruent* with how most people perceive time (as linear)." Subsequent research explored the difference in customer comprehension when comparing two different linear depictions of time. The results show that the use of an enhanced linear design – incorporating several behavioral science elements – yielded a 14% uplift in customer comprehension relative to the circular representation. (See graphics below.)

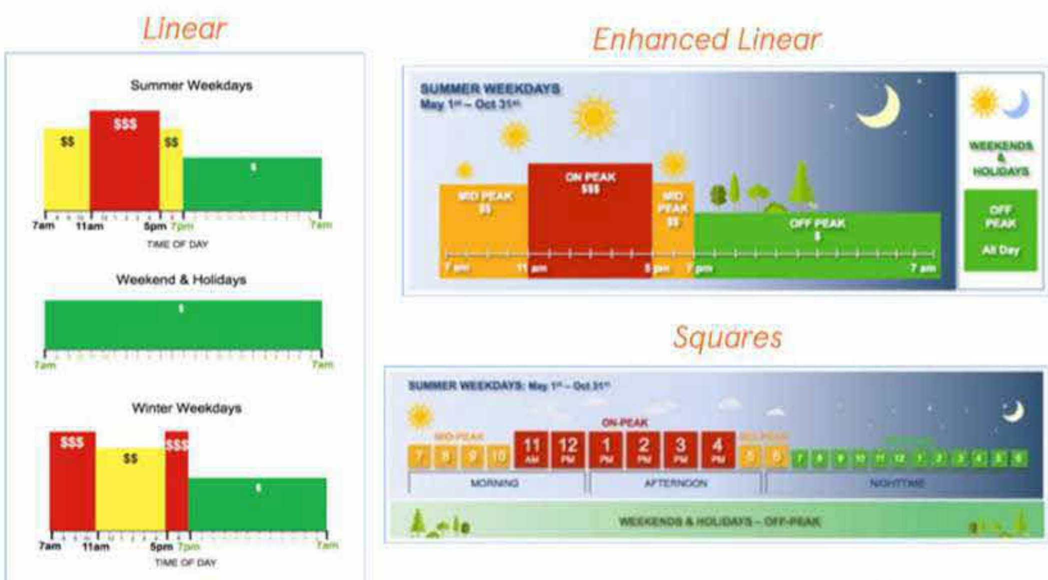
[78] Thaler, R. and C. Sunstein. (2008). "Nudge: Improving Decisions about Health, Wealth, and Happiness. New Haven, CT: Yale University Press.

Figure 16. Example Circular Time Depiction



Source: BEworks 2019 (Ontario bill design findings)

Figure 17. Example Linear and Enhanced Linear Time Depictions



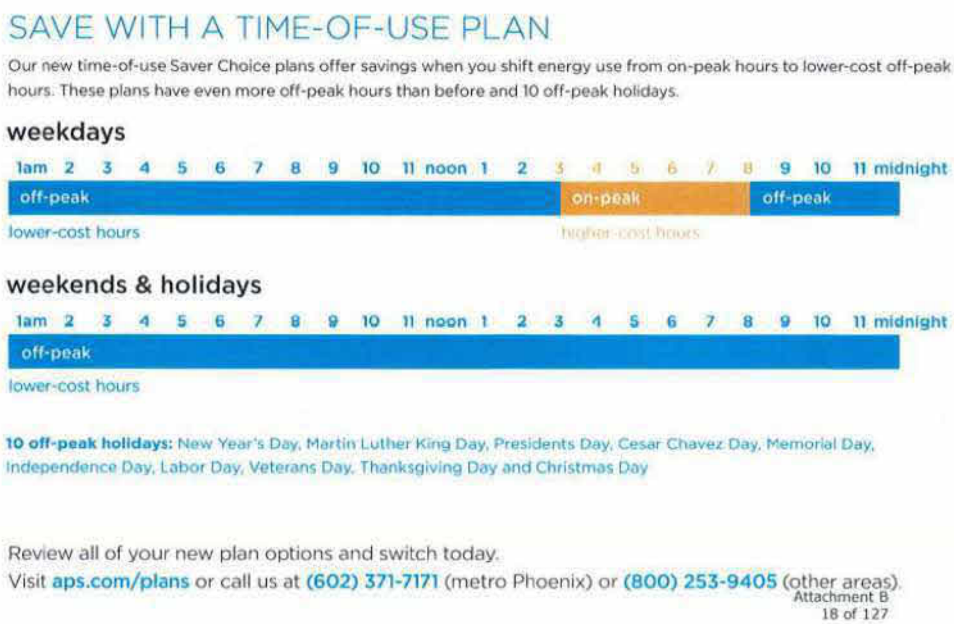
Source: BEworks 2019 (Ontario bill design findings)

Guidehouse's review of APS literature revealed the use of a combination of both circular and linear time depictions to inform customers about TOU rates. (See APS graphics below.) Given the past research described above, APS customers are likely to benefit from modifications to TOU graphics. Guidehouse recommends that APS consider the exclusive use of a linear graphic for future customer communications. Customers may also benefit from the use of an enhanced linear graphic such as the one adopted in Ontario. Guidehouse suggests that APS consider performing customer research and behavioral diagnostics to test the comprehensibility of several graphic designs with different demographic groups including seniors and low-income households.

Figure 18. Example APS Circular Time Depiction

Source: APS

Figure 19. Example APS Linear Time Depiction



Source: APS

3. Helping customers make decisions using rate comparison tools and pro forma billing (strength)

APS's rate comparison tool and pro forma billing provide customers with valuable means of comparing rates and the cost differences between rates, helping people make a rational assessment of rate options based on economic considerations. When studying decision making, behavioral science research has found that when faced with a choice, people tend to employ one of two systems of thinking: System 1 or System 2. System 1 thinking is often described as intuitive and automatic, while System 2 thinking is generally characterized as reflective and rational. Automatic System 1 thinking generally involves making decisions based on a gut reaction, while Reflective System 2 thinking relies on a more conscious thought process.

It is important to note that most utilities tend to design programs with the expectation that customers will employ System 2 thinking when making decisions. Nevertheless, the reality is that most of our decision making relies exclusively or heavily on System 1 thinking. In short, the decisions that utility customers make generally are not as systematically considered as we would like to believe. Instead, people frequently rely on mental shortcuts and rules of thumb due to limitations in the amount of time and energy available to attend to competing concerns. According to Weber and Johnson,[79] attention is a very scarce cognitive resource. "Unlike money or other material resources, which can be saved or borrowed, the amount of attention available to anyone to process the vast amount of information potentially available on innumerable topics is small and very finite."[80]

Moreover, even when people do give their attention to a particular topic, their decisions are often influenced by many different types of biases. One such bias is loss aversion. First, people hate losses. Research suggests that losing something makes people twice as miserable as gaining the same thing makes them happy.[81] As a result, people tend to avoid giving up what they have because they do not want to incur a loss, even when changes are in their best interest. Therefore, in a context of limited attention and loss aversion, tools provide a valuable resource for both making the assessment easier and making the likely outcome clearer. By doing so, tools can help overcome people's tendency to stick with what they have and actively make a change.

The behavioral science insights highlighted here suggest that APS's customer education tools, including the rate comparison tool as well as the more recent effort to provide customers with pro forma billing, are likely to provide great benefit to customers. Although the APS rate comparison tool had a temporary error between February and November 2019, almost 10 months after the rate transition was completed on May 1, 2018, that issue has since been resolved. The recent addition of pro forma billing ensures that all APS customers can easily and quickly compare their current rate to their most economical rate, eliminating the need (but preserving the option) for customers to proactively find and use the rate comparison tool. Such

[79] Weber, E. U. & Johnson, E. J. (2009). "Mindful judgment and decision making." Annual Review of Psychology, 60, 53-86.

[80] Weber, E. (2010). "What Shapes Perceptions of Climate Change?" in *Climate Change*. Wiley Interdisciplinary Reviews (WIREs). January 6, 2010. Available at: https://www0.gsb.columbia.edu/mygsb/faculty/research/pubfiles/4757/WIRE%20ClimateChange%20Perceptions%20Weber.pdf.

[81] Thaler, R. and C. Sunstein. (2008). "Nudge: Improving Decisions about Health, Wealth, and Happiness." New Haven, CT: Yale University Press.

tools are likely to benefit customers by helping them consider the rate choices using a more rational thought process.

Guidehouse recommends that APS consider providing customers with additional tools such as the demand charge calculator to help customers feel more comfortable with demand rate options. Customers could also benefit from the development of a notification system that would notify customers if they are approaching rate plan eligibility thresholds for the flat (basic) rate plan they are currently enrolled in (related to the annual rate reassignment process).

4. Using sweepstakes to promote active enrollment (strength)

Sweepstakes are a great tool for customer engagement. Behavioral science research has shown that people tend to be overly optimistic about their chances of winning lotteries and sweepstakes (as well as succeeding in marriage and business) when compared to the actual odds. For example, when students are asked how well they expect they will do in a college class, only 5% of students report that they will be below the median and more than half the class expects to perform in the top 20%.

Consistent with behavioral best practices, the APS customer engagement and outreach effort successfully designed and implemented a sweepstakes approach to encourage customers to actively choose their new rate as part of the rate transition process. The APS sweepstakes gave away 10,000 smart thermostats and 2,000 smart plugs to a randomly selected list of eligible customers who had selected their new rate. While the impact of the sweepstakes is difficult to discern because it did not have an experimental design, behavioral science research suggests that it is likely to have been impactful in motivating a larger proportion of customers to actively select a new rate. In other words, APS's decision to use a sweepstakes approach is likely to have helped motivate the 22.8% of customer who actively chose their new rate.

5. Understanding and addressing customer motivation in rate comparison tools and pro forma billing (opportunity for improvement)

Behavioral science research and past utility rate studies suggest that customer rate choices are not simply motivated by personal or household economic considerations but often involve a wide range of factors. Such studies indicate that a strict focus on customers' choice of the most economical plan (MEP) as a measure of success is ill-advised. According to customer research from a recent TOU study in Colorado, the three most commonly self-reported factors motivating customers to enroll in the TOU rate were the opportunity to save money (96%), to have more control over their bill (89%), and to conserve energy (88%).[82] These findings are consistent with behavioral science and decision research which show that decision making is not always rational and that both economic and non-economic factors may drive decision making.

According to research on sustainable behaviors, a variety of factors are likely to influence an individual's decisions.[83] These include emotions/affect, personal and cultural values, and personal and social norms, as well as a concern for others (i.e., empathy and pro-social

[82] Guidehouse. (2020). "Residential Energy Time-of-Use (RE-TOU) Trial." Final Evaluation Report prepared for Public Service Company of Colorado.
[83] Steg, L.; Perlaviciute, G., and E. Van der Werff. (2015). "Understanding the human dimensions of a sustainable energy transition." *Frontiers in Psychology: Personality and Social Psychology*: 17. Available at: https://doi.org/10.3389/fpsyg.2015.00805.

behaviors). For example, in the Colorado study, survey research findings revealed that nearly 90% of customers indicated they were highly motivated by the prospect of conserving energy (a reflection of environmental values), 89% by having more control over their bills (reflecting the desire for self-efficacy), and 65% by helping the utility to understand and design an efficient electricity rate for the future. More generally speaking, customers may also value the simplicity and convenience of using flat rates more highly than the potential energy savings that could be achieved via TOU or demand rates.

When deciding whether to provide customers with rate comparison tools or pro forma billing, utilities should be aware that these tools carry the potential for both beneficial and detrimental effects on customer decision making. Given that both tools tend to focus exclusively on helping customers assess the difference in economic benefits between rates, they often fail to acknowledge and tend to crowd-out customers' considerations of the other benefits associated with particular rates, resulting in an outcome where customers may be left with a rate that fails to address the full range of their interests.

While rate comparison tools and pro forma bills provide value by helping customers to rationally and easily assess the economic benefits of different plans (based on historical usage), a more holistic approach to comparing rates would acknowledge and integrate additional factors of value to customers (i.e., level of risk, control, ease, convenience, etc.). Given that APS has recently begun providing pro forma billing to all customers – comparing a customer's current rate to their MEP – we will be able to discern whether customers are most motivated by lowest-cost-economics. Now that all customers will be able to make the comparison quickly and easily, we can assess whether customers who are not on their MEP choose to change rates and adopt their MEP. Such a migration to the MEP would provide quantitative evidence about the portion of customers who may perceive their best interest exclusively in economic terms.

As noted earlier in this report, the choice to provide customers with rate comparison tools and pro forma billing currently represents industry best practices when undertaking rate transitions where customers may move to time-differentiated rates. That said, the exclusive focus on economic benefits unnecessarily shifts customer attention away from other values and benefits that would otherwise be factored into the decision process. In order to overcome these built-in biases, Guidehouse suggests that APS perform additional customer research to learn more about how customers are evaluating rate options, the values that customers reference when making a choice, and potential thresholds for choosing one plan over another.

3.2.2 Customer Experience

6. Designing customer bills to enhance customer understanding and behavior (opportunity for improvement)

The design, layout, and content of critical sources of information such as customer bills plays an important role in shaping customer awareness, knowledge, and behaviors.

In a recent study for the Ontario government, behavioral diagnostics and behavioral research were used to evaluate and restructure the presentation of information in the utility's bill with the goal of enhancing customer understanding. The effort resulted in an increase in customer understanding as well as a reduction in on-peak consumption. The evaluation involved the use of behavioral diagnostics including an eye-tracking method to identify where on the bill customers were most likely to focus their attention. The findings indicated that customers were most likely to pay attention to the top-left part of the page as well as content presented in graphs and tables.

In a revised version of the Ontario bill, more of the information was presented in graphs and tables and important information was moved to the areas of the bill where customers were more likely to look. In this case, the impact was measured using an experimental design with the goal of achieving rigorous evaluation of results. Analysis of research results showed that customer bill comprehension was significantly higher among those customers who received the new bill design when compared to the control group – a 14% uplift in customer understanding. The revised bill also resulted in additional on-peak savings of 0.8% annually and savings of 1.5-2% in winter on-peak.[84]

A review of several recent APS bills (see example in Figure 20 below) suggests that the APS bill design could benefit from the application of existing behavioral insights and/or research to better understand customer comprehension challenges and preferences associated with bill design features. Guidehouse understands that APS plans to perform a bill redesign in the near future and recommends that APS consider the application of current behavioral science insights and/or the use of behavioral diagnostics to evaluate customer comprehension of several potential bill designs.

Figure 20. Example APS Bill


aps

Your electricity bill
Bill date: September 22, 2017

Summary of what you owe

Amount due on your last bill	$44.55
Payment made	-$44.55
Your balance forward	$0.00
Your new charges	
Cost of electricity	$82.09
Total amount due	**$82.09**
Payment due date	**Oct 5, 2017**

[redacted]
YOUR ACCOUNT NUMBER:
[redacted]
FOR SERVICE AT:
[redacted]
Questions?

New Rate Pricing

Important Update about Your E-4 Discount

aps
Your account number [redacted]
Bill date September 22, 2017

Total amount due $ 82.09
Payment due date Oct 5, 2017
Total amount paid $

[redacted]

Source: APS

7. Enhancing effectiveness of communications materials using behavioral insights and behavioral research (opportunity for improvement)

Like the bill evaluations discussed above, behavioral diagnostics have also been used to evaluate the design and framing of a variety of other utility-related communications. How information and communications are "framed" often plays an important role in determining the level of customer comprehension.

[84] BEworks. (2019). "How BEworks Reduced Energy Consumption and Improved Bill Comprehension." Available online at: https://beworks.com/wp-content/uploads/2019/08/CaseStudy3.pdf.

When developing customer-facing materials, the framing of decisions should ideally recognize that people often react differently to the content of communications simply based on how the information is presented. For example, as described by Thaler and Sunstein (2008) framing has been used successfully in energy efficiency campaigns to encourage conservation behaviors by replacing language that originally emphasized potential savings ("If you use energy conservation methods, you will save $350 per year") to language that emphasized potential losses ("If you do not use the energy conservation methods, you will *lose* $350 per year"). Although both statements convey the same information, testing of the loss-aversion based language revealed that it was more effective at creating the desired changes in customer behavior.

Given that message framing and presentation strategies can have such a large impact on customer comprehension of communications content, testing of important communications materials using behavior-based strategies can yield important benefits. For example, behavioral diagnostic studies were employed by Guidehouse to evaluate the content of a utility-run home energy report program as well as the effectiveness of a mobile app developed by a third party. Both studies included a review of the communications content and design being presented to customers with the goal of identifying opportunities to more effectively incorporate behavioral science insights, and enhance customer engagement, motivation, and understanding, with the ultimate goal of encouraging customers to reduce their energy consumption. As a result of the study, an alternative version of the utility's home energy report was developed. The alternative version of the report was subsequently tested and evaluated using an experimental design. The findings revealed that the alternative design which incorporated several important behavioral science insights was successful in generating a 30% increase in report-induced energy savings.

Because of the importance of customer bills and other utility communications for enhancing customer understanding and the lack of prior review, Guidehouse suggests that APS consider the use of behavioral diagnostics and evaluation as a means of enhancing the formatting and content of key rate-related communications such as welcome kits.

8. Nudging shifts in TOU behaviors (strength)

APS's TOU and demand rates are designed to use price signals to encourage people to shift, stagger, and reduce their use of electricity with the goal of saving money. While price signals have been shown to be effective (at least for some customers), an approach that is exclusively focused on economic incentives may not be as effective as an approach that combines the use of economic incentives with non-economic nudges.

An important test of this premise and assessment of the impact of non-economic nudges was recently performed in Ontario. The test followed a full-scale roll out of TOU pricing which occurred in 2012. At that time, average on-peak reductions in Ontario were measured at 3.26%. However, by 2014, on-peak reductions had fallen to 1.18%.[85,86] The decline in customers' price responsiveness as experienced in Ontario was hypothesized to be related to the tendency for people to be present-biased, valuing immediate reward over similar or larger rewards in the future. In other words, customers may learn to perceive the long-term financial rewards

[85] Alectra Utilities. (2019). "Alectra Utilities Regulated Pricing Plan Pilot – Interim Report." Submitted to the Ontario Energy Board. Submitted January 11, 2019. Revised March 29, 2019.
[86] Thomson, D. and D. Carr. (2019). "Insights from the Regulated Price Plan Pilot Project in the Province of Ontario." Presentation at the 2019 Behavior, Energy, and Climate Change Conference. Sacramento, CA.

associated with on-peak electricity reductions as trivial relative to the immediate value of energy services such as doing laundry when it is convenient or heating and cooling the home on hot or cold days. The Ontario Energy Board responded in 2016 by releasing an RFP seeking local distribution companies (LDCs) and partners to participate in a 12-month pilot project to investigate the effectiveness of alternative pricing structures as well as non-pricing interventions on peak consumption. Three non-price intervention approaches were selected for testing: personal benchmarking, personalized tips, and the use of a customer pledge to participate in conservation efforts. The three approaches were combined in a nudge report that was sent to customers on a monthly basis. The research used an experimental design and found that non-price communications (i.e., nudges) were successful in reliably reducing on-peak consumption by approximately 1.5% to 3.5% for all customer groups.[87]

As part of its recent rate transition, APS has also engaged in several noteworthy activities that provide customers with non-economic nudges to shift, stagger, and reduce energy consumption. These activities include the use of bill alerts (prompts), detailed information via the APS app (feedback), and the development of a set of rate-specific tips through the delivery of its Home Energy Report program with Oracle (feedback, segmentation, and social norms). For example, customers have the option to sign up for several different types of notifications including bill alerts that notify customers when they have reached an electricity consumption (kWh), dollar, or peak usage (demand/kW) threshold. These alerts are sent via either text or email. The specific threshold can be determined by customers who want to be made aware of higher than normal levels of energy consumption before they receive their bill. The alert itself serves as a prompt to shift customers' attention to something that they often do not have the time or energy to focus their attention on, allowing them to change their behavior in a timely manner.

A prominent Stanford University behavior scientist, B.J. Fogg, identifies prompts as one of three critical elements in behavior change. One study of the impact of bill alerts on energy savings found that they were successful in helping customers reduce energy consumption by 2.5% annually and up to 6% in peak months.[88]

In the Spring of 2016, APS also launched a mobile app that allows customers to access their account information and monitor and share their energy usage data. The mobile app uses AMI (advanced metering infrastructure) data to provide customers with valuable feedback about their energy usage. In addition, customers on TOU and demand rate plans can view their weekly or daily peak and off-peak usage (demand). The app tool leverages the power of behavioral science insights concerning feedback to improve customer awareness, knowledge, and performance on new rate plans. The value of feedback for changing behavior and reducing energy use has been well documented.[89,90] The power of feedback lies in its ability to make an

[87] Alectra Utilities. (2019). "Alectra Utilities Regulated Pricing Plan Pilot – Interim Report." Submitted to the Ontario Energy Board. Submitted January 11, 2019. Revised March 29, 2019.

[88] Freeman, Sullivan & Co. (2013). "Fast Facts about Bill Alert Pilot." Presentation at the 2013 Behavior, Energy and Climate Change Conference. Available at: https://beccconference.org/wp-content/uploads/2013/12/BECC-Presentation-JAS-Schellenberg.pdf.

[89] Abrahamse, W, Steg, L, Vlek, C, and T. Rothengatter. (2020) "The effect of tailored information, goal setting, and tailored feedback on household energy use, energy-related behaviors, and behavioral antecedents." *Journal of Environmental Psychology* 27(4): 265-276.

[90] Ehrhardt-Martinez, K, Laitner, S, and K. Donnelly. (2010) "Advanced metering initiatives and residential feedback programs: a meta-review for household electricity-saving opportunities." Washington, DC: American Council for an Energy Efficient Economy.

invisible resource (electricity) visible and enables customers to monitor and manage consumption.

Finally, APS has also worked with Oracle (the utility's provider of tailored Home Energy Reports) to redesign the reports with the goal of providing customers with rate-specific feedback about their energy use and tailored tips for reducing energy use and/or energy demand. Home Energy Reports use a variety of data sources and customer segmentation strategies to enhance the relevance of the tips. According to APS and Oracle, the revised reports provide customers with information about their TOU rate plan and encourage them to shift energy use to off-peak hours while also providing energy savings tips that are prioritized based on each customer's unique attributes, ensuring that each tip is relevant to a customer's unique needs.[91,92]

APS has successfully integrated a number of behavioral nudges through its customer bill alerts, APS app-based feedback opportunities, and work with Oracle to provide customers with rate-specific feedback and tips. Guidehouse recommends that APS consider opportunities for expanding these efforts to provide customers with appropriate nudges whenever feasible. One such option that APS might integrate into its larger effort is to provide timely feedback to customers on flat rates who may be approaching rate eligibility thresholds based on their actual electricity consumption, to avoid the involuntary shifting of those customers to new rates.

3.2.3 Behavioral Science Review of the 2017 CEOP & Implementation

From a behavioral science perspective, the APS CEOP was successful at integrating four important behavioral best practices into its outreach and education efforts. These four best practices are summarized in Table 10 below. As discussed in more detail earlier in this report, however, the Guidehouse review also identified four areas in which APS could use behavioral science insights to improve its CEOP activities. The summary table of Guidehouse's findings indicates where behavioral science best practices have been successfully reflected in CEOP activities (representing strengths of the plan) and where behavioral science best practices have not been captured (representing opportunities for improvement).

Table 10. APS Performance for Behavioral Science Best Practices

Strengths	Opportunities for Improvement
• Use of customer choice architecture in the design of rate transition defaults to account for status quo bias and ensure that customers' prior preferences are prominent in the assignment of default rates	• Customer research to better understand and more fully integrate the range of customer values and motivations into the discussion of rate comparison tools and pro forma billing
• Development of rate comparison tools and pro forma billing to promote rational action during customer rate selection	• Use of behavioral diagnostics to enhance the design, formatting, and content of customer bills and improve customer comprehension and behavior
• Use of (smart thermostat) sweepstakes to promote active enrollment	• Design of graphics used to communicate peak and off-peak periods in TOU rates

[91] While bill alerts are available to all customers, customers must opt-in to receive them. The most timely feedback options require that customers download the APS mobile app. Oracle's Home Energy Reports are only provided to a subset of APS customers due to program design requirements and cost/benefit calculations.
[92] Oracle. (2020). "Report Modules." Available online at: https://docs.oracle.com/en/industries/utilities/energy-efficiency/energy-efficiency-overview/Content/Customer_Experience/Report-Modules-eHER.htm.

• Use of "nudges" such as high bill alerts, detailed energy feedback through the APS app, and rate-specific tips (via home energy reports) to shift TOU behaviors	• Application of behavioral research to enhance the effectiveness of key communications materials such as welcome kits

Source: Guidehouse

4.0 Conclusions and Recommendations

As described in detail in this report, **Guidehouse believes APS's 2017 CEOP followed several foundational normative and best practices in its development,** including early stakeholder engagement in its 2016 proposed rate case process, leveraging its substantial historical understanding of residential customer usage and responsiveness to TOU and demand rates, articulating goals and consistent message branding, and integrating the rate transition CEOP with information provided to customers about other utility programs.

While Guidehouse believes APS's 2017 CEOP and its implementation performed well across most practices, there is always room for improvement. Normative and generally accepted best practices across the industry, *tailored to APS's specific customer educational needs, program objectives, and Commission directives*, should guide further improvements and refinements to APS's customer education and outreach approach.

Guidehouse also concludes that comparing the CEOP's performance to California's default residential TOU ME&O program suffers from several important scale and scope flaws, especially in an *ex post facto* evaluation. As discussed at length in Chapter 2.2, APS's and SCE's customer education and outreach plans for their respective rate transitions were shaped by different customer starting points, different customer educational needs, different policy objectives and Commission directives, and were supported by significantly different budgets. As a result, Guidehouse does not believe it is reasonable to compare APS's CEOP to SCE's ME&O plan. There are, however, certain aspects of the California default TOU ME&O work – in addition to an awareness of best practices generally – that offer constructive learnings for rate transition education, and for APS's future customer education and outreach efforts.

Beyond California, many utilities are moving towards modernizing their rates and leveraging digital tools and advanced data capabilities to enhance customer experiences, including education and outreach. One consistent and important theme across these rate modernization efforts is that both economic and non-economic factors should be integrated into the tools and materials used to inform customers about their rate choices. **For this reason, focusing education and outreach solely on the customer's most economical rate plan, or MEP, ignores other considerations that can be very important to customers, and is not considered best practice.**

Behavioral science clearly indicates that most people tend to stick with the status quo or default option when faced with decisions. Behavioral science also indicates that for those people who do make an active choice, a wide range of non-economic factors are likely to influence the decision-making process, including personal and cultural values. While economics remain important, past research has shown that other concerns and preferences also have a strong influence on customer choice. For example, some people are motivated by convenience, while others are concerned about environmental consequences, and still others prefer options that appear to carry less risk. Generally speaking, non-economic considerations tend to be more important when economic consequences are relatively small. **For these reasons, the use of Most-Like Rates (i.e., rates that most closely resemble customers' legacy rates) during APS's rate transition correctly accounted for customers' past rate choices, knowledge, and experience, and likely made the transition easier for them.**

Below, Guidehouse summarizes our recommendations for how APS can improve its CEOP efforts going forward. Generally speaking, APS approached the 2017 CEOP as a marketing effort, focusing on advertising upcoming rate changes. In the future, APS can strengthen this approach by approaching education and outreach more holistically across its rates program and by focusing on establishing and evaluating customer-centric measures including awareness, knowledge, and behaviors as part of a continuous process improvement approach. This type of approach is becoming increasingly common among utilities who have begun to recognize that rates play a key role in shaping the type of utility-customer partnerships that are needed to manage complex, distributed energy systems through enhanced customer engagement and demand management while also maintaining high levels of customer satisfaction.

Accordingly, Guidehouse recommends a multi-year customer engagement initiative for the rates program that incorporates the following elements over the long term, and that could support goals and objectives resulting from APS's pending rate case in the near term:

- **Relating to Customer Research and Experience:** APS should consider conducting customer segmentation and ongoing process evaluation research for a period of 2 to 3 years prior to and following the rollout of new rates to better understand customer perspectives, motivations, barriers, and expectations and how they vary across important segments of the population. Ongoing process evaluation research could be particularly helpful to understand the experience of new and existing customers with a rate plan over time. Importantly, process evaluation research could provide insights into any challenges and misperceptions that dissuade customers from trying new rates or changing their behaviors. This research could be used to inform program outreach activities and materials using a continuous process improvement approach.
    - Process evaluation research methods include, for example, customer surveys, interviews, and focus groups.
    - Research can be used to develop customer journey maps for particular customer segments of interest (such as seniors, Spanish-speaking populations, and low-income households), illustrating customer experiences and the ways in which those experiences shape customer perceptions, thoughts, and feelings about the utility. Journey maps are particularly valuable for identifying pain points, common misunderstandings, opportunities for behavioral nudges, and additional tools.
    - APS has already successfully integrated a number of behavioral nudges through its customer bill alerts, APS app-based feedback opportunities, and work with Oracle to provide customers with rate-specific feedback and tips. Guidehouse recommends that APS consider opportunities for expanding these efforts to provide customers with appropriate nudges whenever feasible; for example, providing timely feedback to customers on flat rates who may be approaching rate eligibility thresholds so as to avoid the involuntary shifting of customers to new rates during the annual reassignment process, when avoidable.
    - APS should also consider additional tool enhancements that facilitate customer engagement and increase rate choice awareness, for example, developing and promoting the demand charge calculator to help customers feel more comfortable with demand rate options.
- **Relating to Behavioral Science Review and Research:** As previously noted elsewhere in this report, given that message framing, message content, and communications design elements can have such a large impact on customer comprehension, testing important communications materials using behavior-based strategies can yield important benefits. For example, an exclusive focus on economic benefits, or bill impacts, fails to recognize other important customer values and interests that influence customers' rate choices. This may

cause customers to end up on a rate that is, on the whole, sub-optimal for them. These outcomes often result in negative customer experiences and lower levels of satisfaction.

Guidehouse recommends that APS perform behavioral diagnostics and research to assess how customers are evaluating rate options and determine the values that customers reference when making a choice (as well as the biases that shape their choice). Guidehouse recommends that APS consider the use of behavioral diagnostics and evaluation as a means both to remove any obstacles for customers to choose the MEP if the most economical price is the customer's priority, and to ensure that customers are aware of the other characteristics of a rate plan that are relevant to their priorities and values.

- Review of program design, communications, and other materials through the behavioral diagnostics lens can strengthen the "choice architecture" and enable APS to apply behavioral nudges as appropriate.
- Customer research and behavioral diagnostics can help to test the comprehensibility of graphic designs options with different demographic groups including seniors, Spanish-language customers, and low-income households.
- Future bill redesign efforts would benefit from the application of existing behavioral insights and/or new research to better understand customer comprehension challenges and preferences associated with bill design features.

➢ **Relating to Objectives, Metrics, and Reporting:** The energy utility industry appears to be moving toward a more programmatic approach to planning, implementing, and evaluating the customer response to new rates, focusing on continuous process improvement and redefining what is considered best practice for metrics and reporting. Guidehouse recommends that APS begin approaching its rates from this perspective by establishing a Program Theory Logic Model and evaluation plan that documents utility goals and evaluates the performance of rate-related initiatives against strategic objectives.[93] Objectives and metrics should focus on the customer experience and the desired customer outcomes. Evaluation findings should be used to inform changes to program efforts and materials in an ongoing cycle of continuous process improvement.

It is important to emphasize that metrics should not only document marketing and education outputs, but also the impact of marketing and education activities on customer awareness, perceptions, knowledge, behavior, barriers, and experience. Such metrics should be modified as needed to adapt to changing customer expectations and rate conditions and progress should be reported on a regular basis. As mentioned, customer education should also seek to attain segment-specific insights for particular customer segments of interest. Overall, evaluation objectives, metrics, and reporting should be based on:

- A Program Theory Logic Model and evaluation plan that specifies goals and objectives as well as customer experience metrics (in addition to marketing and outreach metrics) and that tracks and reports on findings at regular, pre-determined intervals.

[93] The US DOE defines a logic model to be "a plausible and sensible model of how the program will work under certain environmental conditions to solve identified problems." More information may be found at: https://www.energy.gov/eere/analysis/program-evaluation-program-logic.

- Process evaluation research and continuous process improvement practices that improve the customer experience in an ongoing and iterative fashion.

➢ **Relating to Stakeholder Engagement and Input:** External stakeholder input is an important component of not only program design but also objective and metric development. For example, APS noted at the outset of its prior rate case process that a comprehensive customer education and outreach plan would be critical to support the results of the rate case. To that end, APS held numerous stakeholder sessions to build early awareness of the changes it was seeking, which enabled key stakeholders to more actively and substantively participate in the rate case and subsequent settlement process, and to begin formulating their own recommendations early on about how customers should be approached about potential rate changes. Finalizing the 2017 CEOP document, however, involved a comparatively limited stakeholder feedback process defined in Decision No. 76295. Stakeholders had 10 days to file a single set of comments on the CEOP; after that, APS had 10 days to file the final plan.

A regular, ongoing stakeholder engagement process – particularly in an environment where multiple programs and other factors impact rates and customer bills in different ways – is an important vehicle for ensuring transparency. Guidehouse understands that APS has already instituted a Customer Advisory Board and begun recurring stakeholder meetings designed to facilitate such transparency and engagement, and strongly endorses these steps. Guidehouse recommends that APS formalize these regular stakeholder meetings into a Stakeholder Advisory Council (SAC), which could serve as an important sounding board, complementary to the Customer Advisory Board, in the development and tracking of future rate plans and customer education initiatives from a regulatory perspective.

- As APS proceeds through its currently filed rate case, a SAC could help to inform refinements to its CEOP that will integrate related rate changes with other customer-facing programs and tools.
- The SAC could facilitate transparency and clarity and distinguish between program goals (e.g., how to measure customer response to specific rate design changes or options) as opposed to education and outreach goals (e.g., how to measure effectiveness of customer touchpoints, messaging, and tools).
- Beyond these activities, the establishment of a SAC could further provide an interactive means of reporting progress toward goals and objectives, and could even identify opportunities for APS to involve stakeholders and regulators in certain customer behavioral science research processes, such as focus group observation and/or survey development.

Appendix A. Residential Rate Transition Switch Rates

APS reported that 22.8% of its residential customers voluntarily switched to a new service plan during the transition period. The Alexander Report also cites this switch rate, but notes that APS's CEOP did "not establish any goals or objectives to reflect customer switch rates. As a result, it is not possible to determine if this switch rate was reasonable or not."[94]

While the Alexander Report is accurate in stating that the 2017 CEOP did not set a goal for the number of customers it sought to have make a voluntary switch during the transition plan, it is possible to compare the 22.8% to percentage of customers making voluntary selection choices in other rate transitions to make a general assessment.

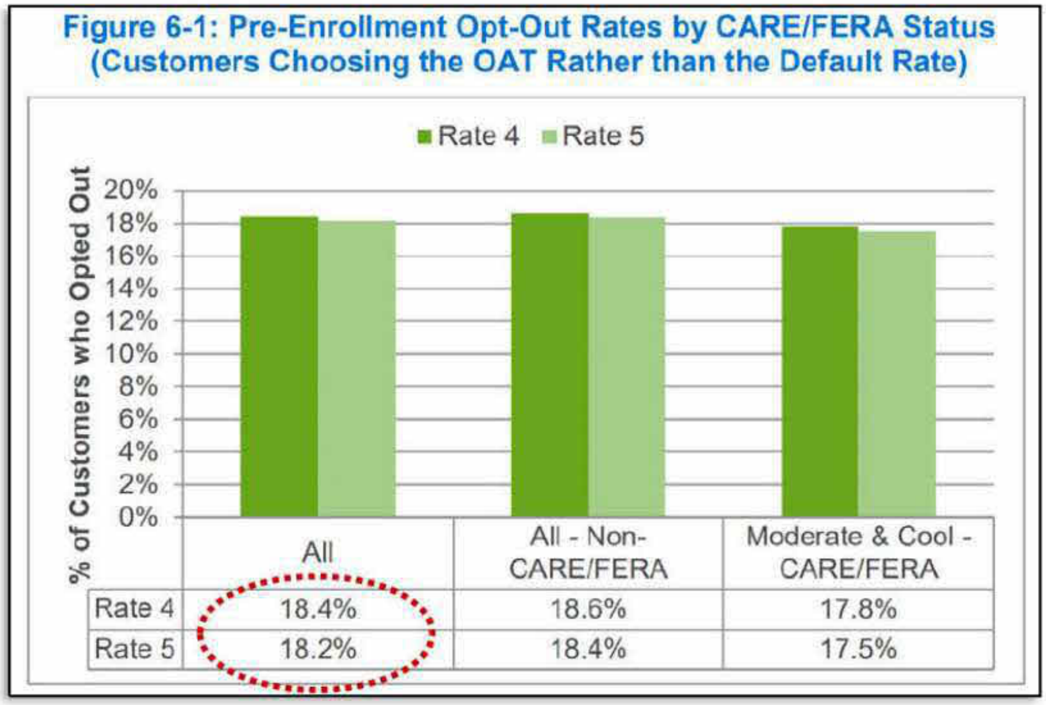
Given the unique characteristics of APS's transition, there is no perfect comparator for this statistic that can readily be gleaned from other utilities' rate transitions. However, since APS rate transition of residential consumers involved APS making a pre-determined choice for customers (in this instance, converting them to their Most-Like Rate) that customers could choose to opt-out of if they wished (given they followed the requirements), it is reasonable to classify APS's rate transition as having a "default" enrollment structure. Using this rate transition default structure, the 22.8% can roughly be compared to other default rate transitions, such as those in California already identified in the Alexander Report.

In preparation for the transition of its qualified residential customers to default TOU rates, SCE executed a default TOU pilot and commissioned an interim evaluation of the pilot results for the June to September 2018 time period.[95] As is typical with default pilot evaluations, Nexant analyzed the percentage of treatment customers who choose to "opt-out" of the default pilot. Or, said in the parlance of APS's rate transition, "customers who voluntarily switched" to a different rate. In both instances, the fundamental choice being made is the same: customers are making an active decision to select a choice other than the default one being made for them by the utility.

Nexant's interim evaluation of SCE's default TOU pilot found that "in most instances, the pre-enrollment opt-out rate was roughly 20%, but once customers enrolled on the rate, very few left."[96] In other words, roughly 20% of SCE's default residential pilot customers voluntarily switched rates. In APS's transition, more customers—22.8%—voluntarily switched rates compared to SCE's default TOU pilot. This result would suggest, that the customer education and outreach APS conducted was roughly as effective as SCE's in engaging customers to make a choice about their rate selection.

[94] Page 22, An Evaluation of Arizona Public Service Company's Customer Education Plan and its Implementation, Barbara Alexander Consulting LLC, May 19, 2020.
[95] "Default Time-of-Use Pricing Pilot Interim Evaluation, Submitted to Southern California Edison", Nexant, April 1, 2019; filed in SCE's 17th Quarterly Report on the Progress of Residential Rate Reform, November 1, 2019.
[96] Ibid., at pg. 8.

Figure 21. SCE Pre-Enrollment Opt-Out Rate Summary



In addition to SCE's default opt-out rate (i.e., "customers who voluntarily switched rates"), there are two other relevant examples to draw from. The first is from SDG&E's full residential default TOU transition, where roughly 16.1% of customers opted-out of the default rate onto another rate, including another TOU rate.[97]

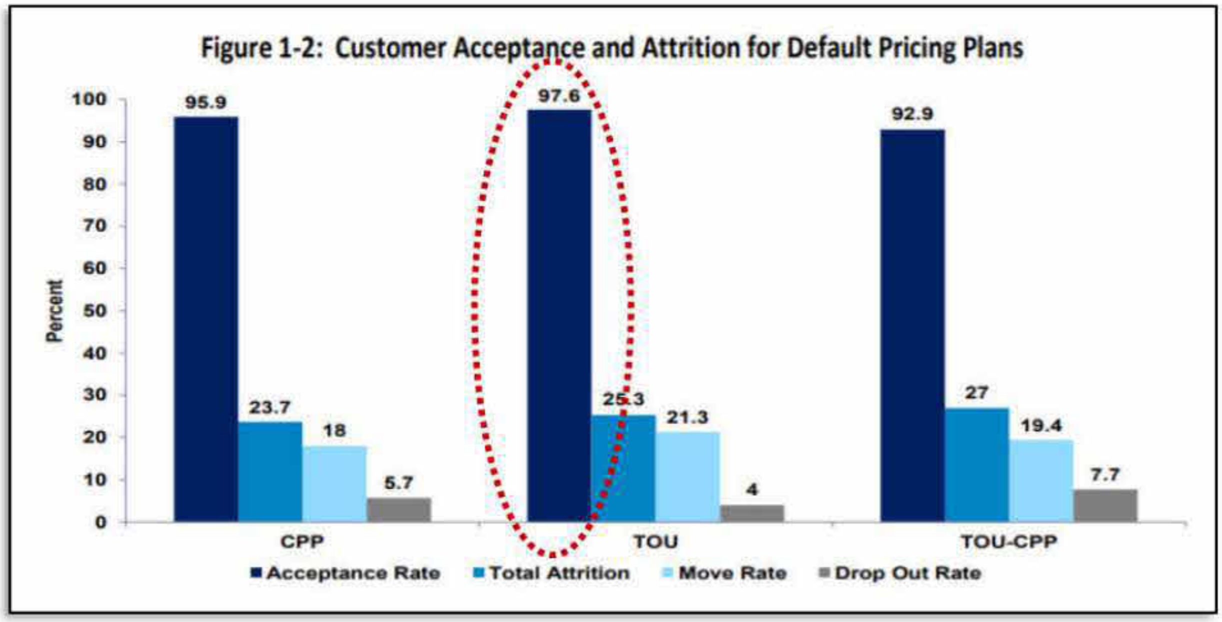
Figure 22. SDG&E Summary of Full Residential Default Transition through 2020 Q1

	Active			Pending						
	Transitioned to TOU-DR1	Opt-in to TOU-DR1	Opt-in to TOU-DR2	Transitioning to TOU-DR1	Opt-in to TOU-DR1	Opt-in to TOU-DR2	Opt-out to non-TOU (DR)	Chose another TOU plan	Attrition	All
Total	411,083	18,937	7,441	118,297	1,004	383	115,979	12,966	110,670	796,759
% of Customers	51.59%	2.38%	0.93%	14.85%	0.13%	0.05%	14.56%	1.63%	13.89%	100%

The second is from Sacramento Municipal Utility District's (SMUD) seminal SmartPricing pilot, which tested multiple rates, including a residential default TOU rate. In this pilot, SMUD observed an opt-out rate of 3% to 7%.[98]

[97] SDG&E's Quarterly Report on the Progress of Residential Rate Reform, May 1, 2020, pg. 14.
[98] SMUD SmartPricing Options Pilot Evaluation, Submitted to Sacramento Municipal Utility", Nexant, August 6, 2014, pg. 3.

Figure 23. SMUD SmartPricing Pilot Summary of Customer Acceptance by Default Rate



As stated above, while none of these examples is a fully valid comparator against APS's rate transition, in all three cases the percentage of customers who voluntarily switched rates was *lower* than APS's. Although it is not possible to state that this result indicates that APS's approach was superior or more effective than SCE's, SDG&E's, or SMUD's, it certainly indicates that APS's customer education and outreach appears to have achieved levels of engagement that were at least as good if not better than these other pilots.

Appendix B. Best Practice Research Sources

No.	Source Name, Scope (if multiple utilities), Link
1	**Source:** Department of Energy (DOE), Final Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies **Scope:** 10 utilities, including (1) Cleveland Electric Illuminating Company (CEIC), (2) DTE Energy (DTE), (3) Green Mountain Power (GMP), (4) Lakeland Electric (LE), (5) Marblehead Municipal Light Department (MMLD), (6) Minnesota Power (MP), (7) NV Energy (NVE), (8) Oklahoma Gas and Electric (OG&E), (9), Sacramento Municipal Electric District (SMUD), and (10) Vermont Electric Cooperative. **Link:** https://www.smartgrid.gov/document/cbs_results_time_based_rate_studies.html
2	**Source:** Environmental Defense Fund (EDF), A Primer on Time-Variant Electricity Pricing **Scope:** 4 utilities, including (1) New Jersey Public Service Electric and Gas, (2) Baltimore Gas and Electric, (3) Oklahoma Gas and Electric, (4) Sacramento Municipal Utility District **Link:** https://www.edf.org/sites/default/files/a_primer_on_time-variant_pricing.pdf
3	**Source:** Uplight, TOU Rate: Five Best Practices for a Successful Customer Rollout **Scope:** 4 utilities, including (1) Fort Collins Utilities, (2) Puget Sound Energy (PSE), (3) Commonwealth Edison (ComEd), (4) California Investor-Owned Utilities (IOUs) **Link:** https://uplight.com/wp-content/uploads/2019/10/U_eBook_TOU_Rate-1.pdf
4	**Source:** Strategen Consulting, TOU Pilot Strategies and Lessons **Scope:** 10 utilities, including (1) Salt River Project (SRP), (2) Baltimore Gas and Electric (BGE), (3) NV Energy, (4) National Grid, (5) California IOUs, (6) SMUD, (7) Arizona Public Service (APS), (8) OG&E, (9) Eversource, (10) Ontario **Link:** https://e21initiative.org/wp-content/uploads/2018/01/e21_Forum_TOUPilotBestPractices_5.05.17.pdf
5	**Source:** Pacific Gas & Electric (PG&E), Revised End of Default Time-of-Use Pilot Communications Strategy **Link:** https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5384-E.pdf
6	**Source:** Sacramento Municipal Utility District (SMUD), SmartPricing Options Final Evaluation: The final report on pilot design, implementation, and evaluation of the Sacramento Municipal Utility District's Consumer Behavior Study **Link:** https://www.smud.org/-/media/Documents/Corporate/About-Us/Energy-Research-and-Development/research-SmartPricing-options-final-evaluation.ashx?la=es&hash=887A78778507B3C909A4D7F9E70BDB78CAC1378A
7	**Source:** Hawaiian Electric Company (HECO), Advanced Rate Design Strategy; and Data Access & Privacy Policy **Link:** https://www.hawaiianelectric.com/documents/clean_energy_hawaii/grid_modernization/dkt_2018_0141_20190925_cos_ARDS.pdf
8	**Source:** AEP Ohio, Time of Use Rates Transition Plan **Link:** https://www.aepohio.com/global/utilities/lib/docs/account/service/choice/oh/TOUTransitionPlanv1.pdf
9	**Source:** Con Edison (ConEd), Outreach and Education Plan 2018 **Link:** http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BE36EB301-7FD8-4F1D-9FD5-30074BFED45E%7D

ATTACHMENT 9

REBUTTAL TESTIMONY
OF
DR. RONALD E. WHITE

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-19-0236

November 2020

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REBUTTAL TESTIMONY
OF
DR. RONALD E. WHITE
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E–01345A–19–0236

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ronald E. White. My business address is 17595 S. Tamiami Trail, Suite 260, Fort Myers, Florida 33908.

Q. ARE YOU THE SAME RONALD E. WHITE WHO FILED DIRECT TESTIMONY ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY IN THIS PROCEEDING?

A. Yes.

I. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I was asked by Arizona Public Service Company (APS or Company) to respond to portions of the pre–filed direct testimonies of: a) Residential Utility Consumer Office (RUCO) witness Frank W. Radigan; and b) Staff witness Ralph C. Smith. More specifically, I was asked to review and comment on recommendations by these two witnesses to reduce depreciation rates recommended by Foster Associates in the 2019 study conducted for APS.[1]

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Estimation of service lives is addressed in Section III. This section discusses limitations of the curve fitting technique employed by RUCO.

The formulation of accrual rates is addressed in Section IV. This section describes RUCO's flawed attempt to develop accrual rates from incorrect average service lives, remaining lives and net salvage rates that Mr. Radigan inserted into a spreadsheet created by Foster Associates.

[1] White Direct Testimony, Attachment REW–2DR.

Section V is responsive to Staff witness Smith's advocacy of abandoning the straight–line method and adopting a "present–value" formulation of net salvage accrual rates. It is demonstrated how a SFAS 143 formulation of accrual rates would inequitably shift the timing of depreciation expense by reducing current accruals and increasing future accruals relative to a straight−line allocation of estimated net salvage.

Section VI provides a summary of depreciation rates and accruals resulting from modifications requested by APS to reduce test year depreciation expense.

III. ESTIMATION OF SERVICE LIVES

Q. PLEASE DESCRIBE THE DEPRECIATION ISSUES RELATED TO SERVICE–LIFE ESTIMATES.

A. As shown in Table 1 below (Columns B and C), RUCO witness Radigan takes exception to 11 of 14 projection lives (P–Life) and three of 14 projection curves (Columns D and E) estimated by Foster Associates for distribution plant included in the 2019 Depreciation Rate Study.

Account Description	P-Life		Curve	
	APS	RUCO	APS	RUCO
A	B	C	D	E
361.00 Structures and Improvements	60.00	65.00	R3	R3
362.00 Station Equipment	45.00	48.00	L0.5	L0.5
364.01 Poles, Towers and Fixtures - Wood	45.00	48.00	L0	L0
364.02 Poles, Towers and Fixtures - Steel	50.00	60.00	R0.5	R0.5
365.00 Overhead Conductors and Devices	50.00	55.00	SC	SC
366.00 Underground Conduit	60.00	65.00	L1	L1
367.00 Underground Conductors and Devices	40.00	44.00	L1	L1
369.00 Services	55.00	65.00	L1	R0.5
370.03 Meters - AMI	15.00	20.00	R3	SC
371.00 Installations on Customers' Premises	45.00	49.00	L0	L0
373.00 Street Lighting and Signal Systems	55.00	65.00	L0.5	R0.5

Table 1. Service-Life Statistics

Q. WHAT IS YOUR UNDERSTANDING OF THE TECHNIQUE USED BY WITNESS RADIGAN TO ESTIMATE SERVICE–LIFE STATISTICS?

A. According to his testimony, projection lives advocated by Mr. Radigan for each of the plant accounts listed in Table 1, Column C above were estimated by fitting Iowa–type survivor curves "with known average service lives" to observed life tables created by

Foster Associates and "… one is chosen as most closely matching the shape of the actual data for the account. The area under the smoothed curve is the estimated service life for the property in the account ..."[2] The technique used by Mr. Radigan is nothing more than a computerized version of visual curve fitting (to an oddly shaped array of data points contained in an observed life table) employed long before the advent of computers.

Q. HOW WAS VISUAL CURVE FITTING EMPLOYED IN THE PAST?

A. Prior to the availability of mechanized systems, a series of survivor proportions obtained from an observed life table was typically plotted on graph paper and overlaid with correspondingly scaled graphs of survivor curves such as the Iowa–type curves. The type–curves were drawn with various average service lives such that both the dispersion and average service life of the observed proportion surviving could be selected from a visual inspection of which curve appeared to best "fit" the data.

A computerized version of the same technique has since replaced manual plotting of points and fitting to survivor curves. The type–curves (such as Iowa) used in such an analysis can be scaled to any average service life, thereby providing a description of both the dispersion (*i.e.*, distribution of retirements over time) and average service life of the fitted data. The "best fitting" curve, however, remains decided by a visual inspection of which curve seems to fit the data points best. Visual curve fitting is an application of *descriptive statistics* used to summarize and describe data through numerical calculations, graphs or tables. It is not an actuarial method of life analysis.

Q. WHAT METHOD DOES FOSTER ASSOCIATES USE IN CONDUCTING STATISTICAL SERVICE–LIFE STUDIES?

A. The statistical method used by Foster Associates is an application of *inferential statistics*. Hazard rates are graduated or smoothed rather than "visually" fitting data points to a survivor curve. This actuarial method draws inferences and predictions about population service–life parameters based on an analysis of samples drawn from the parent population.

[2] Radigan at p. 29, l. 3–6.

Projection lives and projection curves are population parameters "inferred" from a statistical analysis of the underlying forces of retirement described by probability distributions. A projection life is an estimate of mean service–life of the population from which retirements are observed as a random sample. Probability distributions used in estimating service–life statistics are called *survival functions*. The four survival functions are depicted in Figure 1 below.

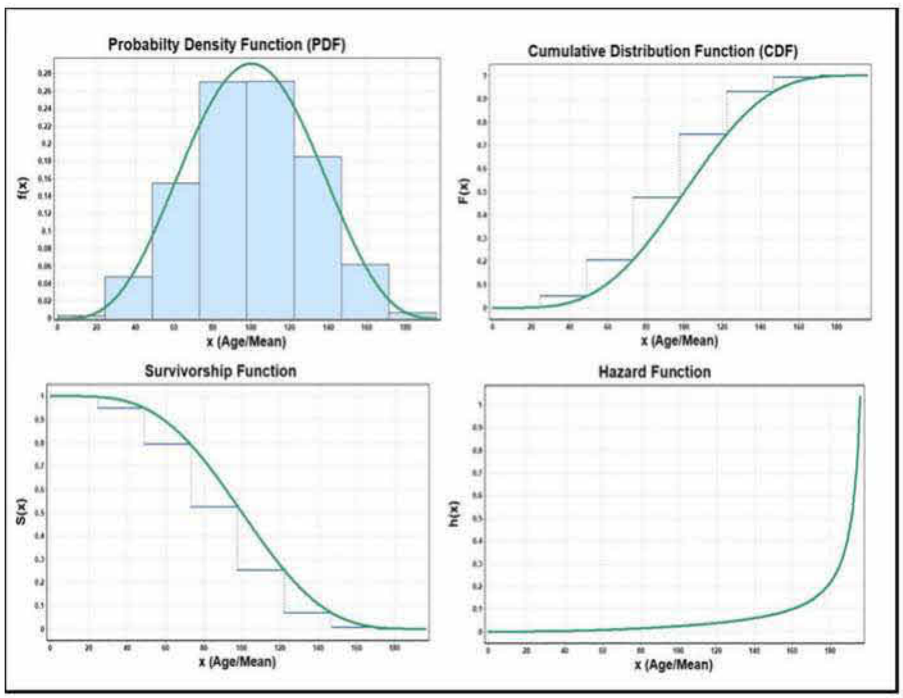

Figure 1. Survival Functions

The associated probabilities are defined as follows:

1. *Probability Density Function*: The probability that a unit of property will be retired between ages t_1 and t_2.
2. *Cumulative Distribution Function*: The probability that a unit of property is retired before age t.
3. *Survivorship Function*: The probability that a unit of property remains in service beyond age t.
4. *Hazard Function:* The probability of nearly immediate retirement from service for a unit of property known to be in service at age t.

The fundamental probability distribution of interest in estimating the service life of industrial property is the *hazard function*. This function, which is also used in reliability theory, describes the conditional probability of retirement (called a *hazard* *rate*) during an age interval given survival to the beginning of the interval. So, for example, the probability that plant that has been in service for 5 years will be retired during the 6th year is a conditional probability of retirement. In other words, the probability is conditioned upon having achieved an age of 5 years.

The objective of a statistical analysis of plant retirements is to estimate the parameters of a function that adequately describes the conditional probabilities of retirement and the underlying forces of retirement.

Polynomials are used to estimate the conditional probabilities of a hazard function. A polynomial can then be transformed into a survivorship function and numerically integrated to obtain an estimate of the projection life of a plant category. Observed proportions surviving are then fitted by a weighted least–squares procedure to the Iowa–curve family—<u>using the projection life derived from the polynomial hazard function</u>—to obtain a mathematical description or classification of the dispersion characteristics of the data. The only purpose of fitting to Iowa curves using the estimated projection lives is to describe forces of retirement with survivor curves more familiar to users of Iowa–type curves than curves described by the coefficients of a polynomial. Absent an understanding of the probabilities associated with survival functions, fitting data points to survivor curves becomes an exercise in finding the best–looking graph. The statistical techniques used by Foster Associates to conduct technically rigorous depreciation studies are not the same as the "visual curve fitting" employed by Mr. Radigan to lengthen the service lives of 11 plant accounts and reduce depreciation rates.

Q. ARE THERE OTHER REASONS TO PREFER THE STATISTICAL TECHNIQUES USED BY FOSTER ASSOCIATES OVER THE CURVE FITTING USED BY MR. RADIGAN?

A. Apart from a difference in the objective (*i.e.*, descriptive vs inferential statistics), the analysis techniques used by Foster Associates overcome a "chaining" problem with curve fitting to observed proportions surviving. Each successive point (*i.e.*, proportion surviving) plotted against a survivor curve is dependent upon the points plotted for prior age–intervals. One or more anomalous or irregular retirements, therefore, will dictate the value of points plotted for subsequent age–intervals. Hazard rates are not "chained." Survivor curves fitted to observed proportions surviving will often produce misleading estimates of projections lives and inaccurate descriptions of the underlying forces of mortality.

In short, the statistical methods used in the 2019 study maximize the informational content of the data and minimize the influence of extraneous events by analyzing the underlying forces of retirement at the level of independent hazard rates.[3] This is not to suggest that an analyst must be highly trained in actuarial statistics to conduct a depreciation study. Absent an understanding and use of more powerful statistical techniques, however, life analysis simply becomes an exercise in trying to fit a curve to an oddly shaped array of data points. It is noteworthy that Staff witness Smith testified that "… the depreciation lives and curves proposed by APS presented in Dr. White's Attachment REW–2 should be adopted for use in this case ..."[4]

IV. FORMULATION OF ACCRUAL RATES

Q. HOW DID MR. RADIGAN DEVELOP HIS PROPOSED DEPRECIATION RATES AND ACCRUALS?

A. It is evident from "his" workpapers that Mr. Radigan used a complex spreadsheet (with formulas intact) designed and developed by Foster Associates. He simply replaced average and remaining service lives (derived by Foster Associates in generation arrangements) for 11 plant accounts with his own flawed calculation of average and remaining service lives. Mr. Radigan also replaced ten net salvage rates with his incorrectly derived rates. The knowledge and effort required to create the spreadsheet is a work product of Foster Associates that was not provided to Mr. Radigan to appropriate, modify and use to derive his accrual rates.

Q. PLEASE EXPLAIN HOW MR. RADIGAN DERIVED FLAWED AVERAGE AND REMAINING SERVICE LIVES.

[3] Although some correlation can be found in the conditional proportion retired, the covariance between the hazard rates in two age–intervals is asymptotically zero. This property has permitted the development of various methods of weighting that reflect serial independence of the disturbance term.
[4] Smith at p. 95, l. 16–18.

A. With the exception of Account 370.30 (Meters –AMI), account total average service lives (ASL) and remaining lives (R/L) were derived by Mr. Radigan using the following formulations:

RUCO ASL= APS ASL+ (RUCO P-Life – APS P-Life);

RUCO R/L = APS R/L + 0.8(RUCO P-Life – APS P-Life).

The above formulations developed by Mr. Radigan will overstate vintage–group average service lives and understate vintage–group remaining lives. It is not clear how Mr. Radigan derived average and remaining lives for Account 370.30. Incorrect formulations of average and remaining lives will produce incorrect rebalanced reserves and incorrect accrual rates.

Correct average and remaining lives are derived in Generation Arrangements as illustrated in White Direct Testimony (Attachment REW–2DR, page 170) and workpapers provided in response to data request RUCO 1.9. An account total ASL is the sum of vintaged plant in service (*i.e.*, age distribution) divided by the sum of vintaged accruals. Vintage accruals are calculated by dividing computed net plant by remaining lives. An account total remaining life is the sum of computed net plant divided by the sum of vintaged accruals. A vintage average service life is the sum of realized life (*i.e.* dollar–years of service provided by each vintage of plant in service) and unrealized life given by the product of a vintage remaining life and associated theoretical proportion surviving obtained from a selected survivorship function.

Q. WHAT IS YOUR UNDERSTANDING OF HOW MR. RADIGAN DERIVED AVERAGE AND REMAINING LIVES FOR FOUR CORNERS UNITS 4–5, ACCOUNT 312.00 (BOILER PLANT EQUIPMENT)?

A. Mr. Radigan first reduced the plant investment recorded on December 31, 2018 by $539,934,000 and the recorded reserve by $13,925,000. Presumably, these adjustments were intended to remove SCR units from the 2019 depreciation study.[5] He then incorrectly retained average and remaining lives derived by Foster Associates.

[5] The RUCO adjustment to plant and reserves is addressed by APS witnesses Blankenship and Lockwood.

Reducing the plant investment will change the age distribution of surviving plant and the average service life used in rebalancing depreciation reserves. Depreciation rates derived by Mr. Radigan for all Four Corners Units 4–5 plant accounts are therefore incorrect.

Q. PLEASE EXPLAIN HOW MR. RADIGAN DERIVED FLAWED NET SALVAGE RATES.

A. Mr. Radigan changed 10 distribution net salvage rates. In doing so, average net salvage rates were set equal to future rates. This is incorrect. Average net salvage rates are derived in Foster Associates Statement E and automatically reported in Statement H. Mr. Radigan manually overrode average net salvage in Statement H, thereby producing incorrect computed (or theoretical) reserves used in rebalancing recorded depreciation reserves. Depreciation rates derived by Mr. Radigan for all distribution plant accounts are therefore incorrect.

V. Formulation of Net Salvage Accrual Rates

Q. WHAT IS YOUR UNDERSTANDING OF STAFF'S RECOMMENDED APPROACH FOR ACCRUING FOR NET SALVAGE?

A. According to Staff witness Smith, "… Staff is recommending a different approach to the cost of removal[/negative net salvage] component of depreciation rates which minimizes the amount of future inflation borne by current ratepayers. Staff's recommended approach is similar to calculations performed by APS witness Dr. White in other jurisdictions including Maryland and the District of Columbia …"[6]

Q. WHY ARE FUTURE NET SALVAGE AND DISMANTLEMENT COSTS ESCALATED FOR INFLATION IN COMPUTING DEPRECIATION RATES?

A. Revenue requirement created for cost of removal must be recovered in dollars sufficient to pay the cost of removal or dismantlement costs when the associated plant is retired and removed from service. The extent to which past inflation is captured in the ratio of removal expense to retirements is a function of both the rate of change in the cost of labor required to remove plant from service and the rate of change in the in-

[6] Smith at p. 95, l. 24 ff.

stalled unit cost of plant removed. This is why a present value treatment of dismantlement costs (*e.g.*, SFAS 143) discounts current dollars escalated for inflation.

Q. WHAT IS YOUR UNDERSTANDING OF THE TREATMENT OF NET SALVAGE ADVOCATED BY STAFF?

A. According to Staff witness Smith:

> From a regulatory perspective, the objective of public utility depreciation is straight-line capital recovery. This is accomplished by allocating the original cost of assets to expense over the lives of those assets through the application of depreciation rates to plant balances. Additionally, many state regulatory commissions, including the ACC, have allowed utilities to recover through the commission–authorized depreciation rates, the utility's estimated future cost of removal, which is part of the net salvage component of the depreciation rates.[7]

Notwithstanding his acknowledgement of the prevalent use of straight–line depreciation, Staff, as noted earlier, is recommending a "different approach" to the cost of removal component of depreciation rates in this proceeding. The "different approach" is a SFAS 143 formulation developed by Foster Associates and sponsored in testimony before the Maryland and District of Columbia Public Service Commissions. Foster Associates' formulation was presented in the 2019 APS depreciation study, as directed in a Settlement Agreement in Docket No. E–01345A–16–0036.

Q. DID YOU ADVOCATE A SFAS 143 FORMULATION OF ACCRUAL RATES FOR NET SALVAGE IN THE MARYLAND AND DISTRICT OF COLUMBIA PROCEEDINGS?

A. I did not. My testimony was initially filed to correct a flawed SFAS 143 formulation advocated by opposing witnesses. Testimony was subsequently filed before the same commissions in compliance with directives to use a SFAS 143 formulation in future depreciation rate applications.

Q. HAVE OTHER COMMISSIONS REJECTED A PRESENT VALUE FORMULATION OF ACCRUAL RATES FOR NET SALVAGE?

A. Yes. The Michigan Public Service Commission is one example. In its decision in Case No. U−15699, the Commission found:

[7] Id. at p. 77, l. 2–7.

> In the [Case No. 14292] order, the Commission observed, among other things, that, "an SFAS No. 143 approach applied to required [asset retirement obligations] ARO and other ARO accounts would be informative, even if the Commission determines that SFAS No. 143 should not be used for ratemaking." The Commission then directed the large utilities to file new depreciation cases cal-culating cost of removal expense using various methods.
>
> The Commission agrees with the Staff that continued use of the traditional, straight–line depreciation method, coupled with the use of the Staff's proposed SRUs on a going–forward basis is the most appropriate means of addressing Mich Con's future removal costs. As discussed by Dr. White in his rebuttal testimony, neither the Attorney General nor ABATE offered a better method for allocating future net salvage than the traditional straight–line method, and the Commission agrees that the simplicity of the traditional method far outweighs the complexity of attempting to change to either of the methods proposed by the Attorney General or ABATE.[8]

Q. IS A SFAS 143 FORMULATION OF ACCRUAL RATES FOR NET SALVAGE APPROPRIATE FOR NON-LEGAL ASSET RETIREMENT OBLIGATIONS?

A. In my opinion, it is not. A threshold question regarding the appropriateness of a SFAS 143 formulation of accruing for non–legal AROs (*i.e.*, cost of removal or net salvage) is whether or not such amounts have risen to the level of an accounting liability. While it is true that a SFAS 143 model can be used to shift the timing of net salvage accruals (as can other models), arguments for using a SFAS 143 formulation are less than persuasive when the rationale for the pronouncement is revisited.

Given the SFAS 143 framework for determining the existence of a liability, it is indisputable that estimated future net salvage does not rise to the level of an accounting liability. The act of voluntarily removing plant and equipment does not create a present duty or responsibility to transfer assets or provide services to another entity as the result of an obligating event that has already occurred. Accordingly, the notion of accreting a non–existent liability to shift the timing of net salvage accruals is a misplaced application of a model designed to disclose the fair value of a liability and period–to–period changes in the liability resulting from the passage of time or revisions to either the timing or the amount of the original estimate of cash flows.

[8] Michigan Public Service Commission, Case No. U–15699, Opinion and Order (dated March 18, 2010), at 11 ff.

Q. IS RECOGNITION OF TIME VALUE OF MONEY IN ACCRUING FOR NET SALVAGE A FLAWED CONCEPT?

A. No, it is not. But who should pay for future cost of removal (and when) are policy decisions regulators must make. A decision to postpone capital recovery and accruals for net salvage, however, is not without costs. A reduction in depreciation accruals achieved by deliberately shifting the timing of capital recovery will reduce internal cash generation and expose current customers to higher marginal costs of incremental external financing. This is not to suggest that internal cash generation should be substituted for the goals of depreciation accounting. However, the potential for increasing (or reducing) the marginal cost of external financing by shifting the timing of depreciation expense is a consequence that should not be ignored.

Q. COULD YOU ILLUSTRATE HOW THE TIMING OF ACCRUALS FOR NET SALVAGE WOULD BE SHIFTED BY THE USE OF AN INTEREST RATE?

A. Figure 2 below provides a comparison of the timing of straight–line vs SFAS 143 accruals for Four Corners Units 4–5 and Common dismantlement costs.[9]

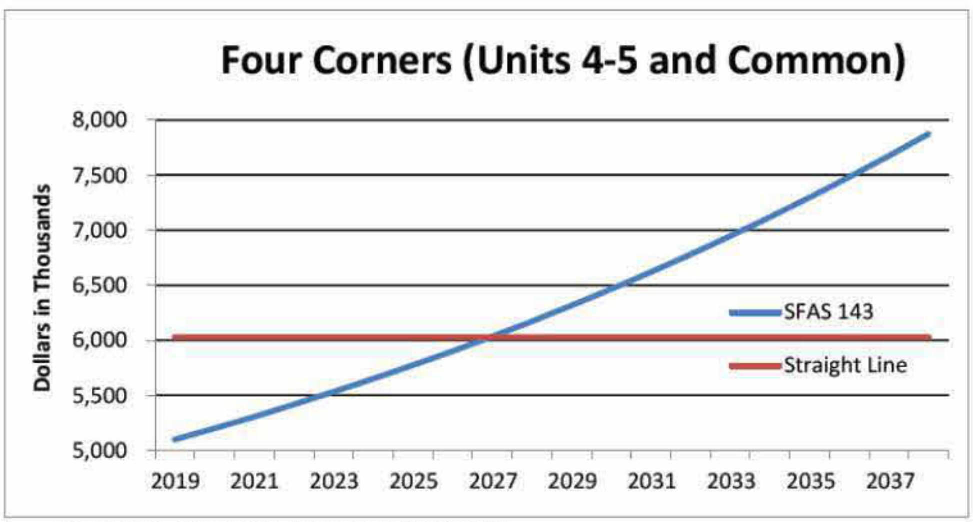

Figure 2. Straight–line vs SFAS 143

It can be observed from Figure 2 that SFAS 143 accruals in 2019 would be approximately $1.0 million lower than straight–line accruals. The difference in accruals becomes gradually smaller until 2028 when SFAS 143 accruals begin to exceed

[9] Plotted accruals exclude net salvage for interim retirements. Future dismantlement costs escalated to year 2038 are $150,761,805 and the SFAS 143 discount rate is 3.78 percent.

straight−line accruals. In 2038, SFAS 143 accruals are about $1.3 million higher than straight−line. Clearly, a SFAS 143 formulation of accrual rates would shift the timing of depreciation expense by reducing current accruals and increasing future accruals relative to a straight–line allocation of unavoidable dismantlement costs.

Q. PLEASE SUMMARIZE YOUR RESPONSE TO THE STAFF–RECOMMENDED PRESENT VALUE FORMULATION OF NET SALVAGE ACCRUAL RATES.

A. The SFAS 143 method recommended by Staff appears to serve no other useful purpose than to reduce current depreciation rates. The threshold question is not if or how time value of money should be reflected in formulating depreciation rates; the question the Commission must first decide is who should pay for future costs of removal (and when). Any number of models can be used to deliberately shift the timing of depreciation expense depending upon the desired result.

Given, however, the complexity of introducing time value of money in the formulation of accrual rates for net salvage, a strong argument can be made for retaining the treatment endorsed by regulation for nearly 100 years. The simplicity of the straight–line method far outweighs the complexity of attempting to shift the timing of net salvage accruals to achieve a reduction in current depreciation expense, increase future expense and potentially increase the marginal cost of external financing. I firmly believe that introducing time value of money in the computation of net salvage accruals is unnecessary and would only serve to further complicate the development and regulation of depreciation rates. I would urge the Commission to retain the current formulation of straight–line accruals for net salvage.

VI. Modified Depreciation Rates and Accruals

Q. PLEASE EXPLAIN WHY FOSTER ASSOCIATES WAS REQUESTED BY APS TO MODIFY DEPRECIATION RATES RECOMMENDED AND FILED IN THE 2019 DEPRECIATION RATE STUDY.

A. It is my understanding that, after considering the direct testimony of intervenors, the Company sought ways to mitigate the impact of the rate increase request on its customers after its initial rate Application was filed. In concert with other mitigation measures, Foster Associates was requested to reduce depreciation rates by: a) Extending the life–span of non–legacy solar power stations by 10 years; and b) reducing the amortization period of the Palo Verde reserve excess from nine to six years.

Q. PLEASE SUMMARIZE THE CHANGES IN DEPRECIATION RATES AND ACCRUALS RESULTING FROM THE REQUESTED MODIFICATIONS.

A. Table 2 below provides a summary of the changes in annual rates and accruals resulting from the requested modifications.

	Accrual Rate			2019 Annualized Accrual		
Function	Filed	Modified	Difference	Filed	Modlified	Difference
A	B	C	D=C-B	E	F	G=F-E
Production						
Steam	5.02%	5.02%		$102,807,136	$102,807,136	
Nuclear	0.96%	0.31%	-0.65%	28,470,493	9,351,926	(19,118,567)
Other	4.00%	3.77%	-0.23%	129,300,016	121,764,783	(7,535,233)
Transmission	2.01%	2.01%		2,761,160	2,761,160	
Distribution	2.51%	2.51%		157,904,801	157,904,801	
General Plant	6.14%	6.14%		57,485,130	57,485,130	
Total	3.07%	2.89%	-0.18%	$478,728,736	$452,074,936	($26,653,800)

Table 2. Filed vs Modified Rates and Accruals

It can be observed from Table 2 that the change in the composite accrual rate is a reduction of 0.18 percentage points and the change in total accruals is a reduction of $26,653,800.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

ATTACHMENT 10

REBUTTAL TESTIMONY OF ANN E. BULKLEY

On Behalf of Arizona Public Service Company

Docket No. E-01345A-19-0236

November 6, 2020

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REBUTTAL TESTIMONY OF ANN E. BULKLEY
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-19-0236)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Ann E. Bulkley, and I am a Senior Vice President of Concentric Energy Advisors, Inc. (Concentric). My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS REBUTTAL TESTIMONY?

A. I am submitting this Rebuttal Testimony on behalf of Arizona Public Service Company (APS or the Company), a wholly-owned subsidiary of Pinnacle West Capital Corporation (Pinnacle West).

Q. DID YOU PREVIOUSLY SUBMIT TESTIMONY IN THIS PROCEEDING?

A. Yes. I submitted Direct Testimony regarding the appropriate Return on Equity (ROE), capital structure, and Fair Value Rate of Return (FVROR) for APS in this proceeding.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to the cost of capital issues within the Direct Testimonies of Mr. David C. Parcell on behalf of the Utilities Division Staff (Staff) of the Arizona Corporation Commission (Commission), Mr. John A. Cassidy on behalf of the Residential Utility Consumer Office (RUCO), Mr. Christopher C. Walters on behalf of the U.S. Federal Executive Agencies (FEA), and Mr. Kevin C. Higgins on behalf of Freeport Minerals Corporation and Arizonans for Electric Choice and Competition (collectively AECC) (collectively, the Opposing ROE Witnesses).

Q. HAVE YOU PREPARED ANY EXHIBITS TO SUPPORT YOUR ANALYSIS AND RECOMMENDATIONS?

A. Yes. My recommendations are supported by the data presented in Attachments AEB-1RB through AEB-11RB, which have been prepared by me or under my direction.

Q. HOW IS THE REMAINDER OF YOUR REBUTTAL TESTIMONY ORGANIZED?

A. The remainder of my Rebuttal Testimony is organized as follows:

- In Section II, I provide a summary and overview of my Rebuttal Testimony.
- In Section III, I provide a comparison of the ROE recommendations in this proceeding to authorized returns for integrated electric utilities in other jurisdictions.
- In Section IV, I update the ROE analysis and recommendations from my Direct Testimony based on market data through September 30, 2020.
- In Section V, I provide a summary of capital market conditions and their effect on the cost of equity for APS.
- In Section VI, I respond to Mr. Parcell's analyses and recommendations.
- In Section VII, I respond to Mr. Cassidy's analyses and recommendations.
- In Section VIII, I respond to Mr. Walters' analyses and recommendations.
- In Section IX, I respond to Mr. Higgins' recommendation.
- Finally, in Section X, I summarize my conclusions and recommendation.

II. SUMMARY AND OVERVIEW

Q. PLEASE PROVIDE AN OVERVIEW OF THE OPPOSING WITNESSES ROE RECOMMENDATIONS IN THIS PROCEEDING.

A. As shown in Figure 1, the Opposing ROE witnesses have recommended ROEs in a range from 8.74 percent to 9.40 percent. The FVROR recommendations of the Opposing ROE witnesses range from 4.69 percent to 5.18 percent.

Figure 1: ROE Ranges and Recommendations of the Opposing ROE Witnesses[1]

	Mr. Parcell (Staff)	**Mr. Cassidy (RUCO)**	**Mr. Walters (FEA)**
Constant Growth DCF	8.70%-9.30%	8.00%-9.50%	9.31%-9.50%
Sustainable Growth	N/A	N/A	8.74%-9.18%
Two-Stage DCF	NA	N/A	8.64%-8.78%
Recommended DCF Results	**9.00%**	**8.75%**	**9.10%**
CAPM	6.40%-6.60%	7.64%-7.73%	8.31%-12.16%
Recommended CAPM Results	**6.50%**	**7.68%**	**9.6%**
Risk Premium Results	8.25%-9.07%	N/A	8.50%-9.20%
Recommended Risk Premium Results	**8.70%**	N/A	**9.00%**
Comparable Earnings Results	8.5%-12.1%	9.50%-10.00%	N/A
Recommended Comparable Earnings Results	**9.50%**	**9.75%**	N/A
ROE Recommendation	**9.40%**	**8.74%[2]**	**9.30%**
FVROR Recommendation	**5.03%-5.11%**	**4.69%**	**5.18%**

[1] AECC Witness Higgins did not perform his own ROE analysis and did not provide specific ROE or FVROR recommendations. Therefore, his testimony is not included in this summary table.

[2] Mr. Cassidy's recommendation is based on an ROE of 8.94 percent less a proposed penalty of 20 basis points.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF YOUR RESPONSE TO STAFF WITNESS PARCELL WITH RESPECT TO THE APPROPRIATE ROE FOR APS.

A. Mr. Parcell recommends an ROE of 9.40 percent and relies on a 0.00 percent to 0.30 percent Fair Value Increment (FVI) cost rate for APS.[3] Mr. Parcell performs a Constant Growth Discounted Cash Flow (DCF) analysis, Capital Asset Pricing Model (CAPM) analysis, Risk Premium analysis and a Comparable Earnings analysis to estimate the cost of equity for APS.[4] He contends that his ROE recommendation of 9.40 percent is reasonable based on his view that the current low interest rate environment has reduced the cost of equity for electric utility companies. It is interesting to note that while the results of Mr. Parcell's analyses suggest significant reductions in the cost of equity, from 82 basis points to nearly 200 basis points from the time that he provided testimony to this Commission in 2016 on behalf of Staff in the Tucson Electric Power case (Docket No. E-01933A-15-0322), and he spends an extensive amount of his testimony discussing the low interest rate environment, his recommended ROE for APS in this proceeding is five basis points higher than his recommended ROE for TEP in the referenced 2016 docket.

Considering his CAPM analysis, it is clear that the result of this model at 6.40 percent is too low to be considered a reliable estimate of the investor required return on equity. Mr. Parcell's CAPM result is 192 basis points lower than the results presented in the 2016 TEP case. Even though he suggests that his CAPM results provide some probative value in this proceeding, in recommending a higher ROE for APS in this case than in the TEP case, he has essentially disregarded the unreasonable results of his CAPM analysis.

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[3] Direct Testimony of David C. Parcell, at 3.
[4] *Ibid*.

As discussed in my Direct and Rebuttal Testimonies, while interest rates in recent years have been at low levels as a result of Federal Reserve monetary policy, current and projected capital market conditions fully support an ROE above 9.40 percent. The specific areas of disagreement with Mr. Parcell's ROE analyses are summarized below:

- Mr. Parcell's 9.40 percent ROE recommendation for APS is 25 basis points below the average equity returns that have been authorized for integrated electric utilities nationwide since January 2018 (9.65 percent), and it is lower than approximately 86 percent (55 out of 64) of the returns authorized during that period.

- I disagree with the range of returns that Mr. Parcell considers reasonable. While Mr. Parcell's ROE analyses result in a range of equity returns from 6.40 percent (the low end of his CAPM results) to 12.10 percent (the high end of his Comparable Earnings results), he eliminates the high end of his results, narrowing his final range of reasonable results to 6.40 percent to 10.00 percent.[5, 6]

- Mr. Parcell suggests that the CAPM results of 6.40 percent and 6.60 percent have probative value to demonstrate that risk premiums are lower currently than in previous years due to lower equity returns, and he suggests that this reflects a decline in investor expectations of equity returns.[7] Finally, Mr. Parcell rationalizes his CAPM results based on lower interest rates. Mr. Parcell's CAPM return estimate is 235 basis points below any authorized ROE for any integrated electric utility over the last 30 years. Furthermore,

[5] Direct Testimony of David C. Parcell, at 34, 38.
[6] *Id.*, at 3.
[7] *Id.*, at 45.

these results are 300 basis points below his final recommended ROE for APS and should not be relied on by the Commission as having any meaningful representation of the investor-required return on equity.

- Mr. Parcell's criticism of my DCF analysis is entirely inconsistent with his own analysis. Mr. Parcell relies on studies that are nearly a decade old and therefore do not consider current regulations on the financial community in an attempt to discredit reliance on projected earnings per share (EPS) growth rates in the DCF model. However, the high end of his range of results of 9.30 percent can only be achieved by using projected EPS growth rates and the proxy group that I relied on in my Direct Testimony, which he also suggests is not appropriate.[8]

- Mr. Parcell introduces a Risk Premium analysis that relies on historical ranges of risk premiums to estimate the ROE. It is important to note that Mr. Parcell's analysis ends in 2019, and therefore does not consider the current and recent market conditions in the estimate of the risk premium, which is inconsistent with his use of current market data in the remainder of his ROE estimation methodologies.

- Mr. Parcell's Comparable Earnings analyses is reliant on historical data, which are subject to a host of accounting and operational issues that have no bearing on forward-looking return projections. Furthermore, his Comparable Earnings analysis does not consider any market data in 2020. As such, this analysis does not reflect how current market conditions may vary from the long-term historical data that is relied upon in his analysis. While Mr. Parcell suggests that this is to avoid undue influence from unusual or abnormal conditions that may occur in a single year, he relies on

[8] Direct Testimony of David C. Parcell, Exhibit No. ___(DCP-1), Schedule 7.

exactly that data in his DCF and CAPM models. It is inconsistent to exclude current market data from the Comparable Earnings analysis and yet rely entirely on that data for the assumptions used in the DCF and CAPM models. Mr. Parcell relies on the results of his DCF analysis using the proxy group relied upon in my Direct Testimony to set the high end of his range of DCF results. However, in establishing the range of results for his Comparable Earnings analysis, he relies on his proxy group, excluding from his range of results the "Historic ROE" mean and median results of 11.60 percent to 12.10 percent and the "Prospective ROE" results of 10.50 percent to 10.60 percent that are based on my proxy group companies.

- Comparing Mr. Parcell's Comparable Earnings analysis to his Risk Premium analysis demonstrates further inconsistencies in his analytical approaches. While Mr. Parcell suggests that an 18-year history is appropriate for his Comparable Earnings analysis, he suggests that a longer-term analysis of the Risk Premium, such as was developed in my testimony, would not be appropriate. In this case, Mr. Parcell concludes that the proper duration of the analysis should be five years, so as not to include the effects of other changes in regulation that may have occurred over time. Mr. Parcell does not explain how it is that the effects of changes in regulation over time would not also affect his Comparable Earnings analysis. While it appears that Mr. Parcell believes that his Risk Premium analysis is more appropriately conducted with more current data, he does not include any data on authorized ROEs in 2020 in his analysis.[9]

[9] Direct Testimony of David C. Parcell, at 43.

Q. PLEASE SUMMARIZE YOUR RESPONSE TO MR. PARCELL WITH RESPECT TO THE FVROR.

A. Mr. Parcell calculates the FVROR using two approaches. The first approach relies on a 0.00 percent return on the FVI. The second approach uses the average of his calculation of the real risk-free rate which he estimates to be 0.60 percent, and estimates the return on the FVI to be the midpoint of 0.00 percent and his calculation of the real risk free rate, resulting in a return on the FVI of 0.30 percent.[10] Mr. Parcell estimates the nominal risk-free rate to be 2.60 percent and deducts an estimate of inflation of 2.0 percent to estimate the real risk-free rate of 0.60 percent. Mr. Parcell's proposed cost rate for the FVI is lower than what is reflective of current market conditions because of the nominal risk-free rate Mr. Parcell has relied on. As shown in Attachment AEB-8RB, adjusting the nominal risk-free rate used in Staff's FVROR to the Duff & Phelps normalized risk-free rate used in the analysis presented in my Direct Testimony and relying on the yield on inflation protected securities, increases the real risk-free from 0.60 percent to 0.93 percent. The midpoint of this real risk-free rate and zero would be 0.47 percent. As shown in Attachment AEB-10RB, updating Mr. Parcell's analysis to rely on this return on the FVI would result in a FVROR of 5.16 percent. Furthermore, updating to the Company's requested return on the FVI of 0.80 percent, which is in the range that is established by this revised calculation of the risk-free rate, results in a FVROR of 5.25 percent.

Q. PLEASE SUMMARIZE YOUR RESPONSE TO RUCO WITNESS MR. CASSIDY'S ROE RECOMMENDATION FOR APS.

A. As shown in Figure 1 above, the ROE results presented by Mr. Cassidy range from 7.64 percent to 10.00 percent. This range is defined by his CAPM analysis results on the low end and his Comparable Earnings analysis results on the high end. Mr.

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[10] *Id.*, at 53-54.

Cassidy's recommended ROE of 8.74 percent (8.94 percent less a 20 basis point reduction for management performance) is 126 basis points below the 10.00 percent return that was authorized for APS in August 2017,[11] and it is approximately 91 basis points below the average equity returns that have been authorized for integrated electric utilities nationwide since January 2018 (9.65 percent). Mr. Cassidy's recommended ROE is not a reasonable estimate of the cost of equity for APS for the following reasons:

- The results of Mr. Cassidy's Constant Growth DCF model range from 8.00 percent to 9.50 percent. Mr. Cassidy assigns 40 percent weight to the midpoint DCF estimate of 8.75 percent in deriving his base ROE recommendation. Mr. Cassidy fails to take into consideration, however, that the DCF model is not producing reasonable results under current market conditions due to the high valuations and low dividend yields of the proxy group companies, which are not considered sustainable by analysts. This calls into question the reliability of the DCF model results under current market conditions.

- Mr. Cassidy also considers growth rates from a variety of sources in his DCF analysis, including historical and projected retention growth rates from Value Line, historical and projected earnings per share, dividends per share and book value per share from Value Line, and projected earnings per share from Yahoo! Finance. Mr. Cassidy fails to recognize that the use of growth rates other than projected earnings growth rates in his DCF model produces return estimates that have not been observed for any integrated electric utility in at least the past 35 years. Only the use of projected EPS growth rates from Yahoo! Finance provides a somewhat reasonable, albeit low,

[11] Docket No. E-01345A-16-0036, Settlement Agreement adopted by the Commission August 15, 2017.

DCF estimate of 9.58 percent. The use of other growth rates in the DCF model is not appropriate for reasons I will explain in my Rebuttal Testimony.

- The mean result of Mr. Cassidy's CAPM analysis is 7.68 percent. Even though this return estimate is well below any authorized ROE for an integrated electric utility in the past 35 years, Mr. Cassidy places 20 percent weight on this return estimate in arriving at his base ROE recommendation of 8.94 percent. Mr. Cassidy suggests that his CAPM estimate demonstrates that the cost of equity has declined and that his DCF model results are reasonable. Mr. Cassidy relies on the current three-month average yield on 20-year Treasury bonds as his risk-free rate of 1.16 percent and a historical market risk premium (MRP) of 7.40 percent. Yields on both government and corporate bonds are near historical lows but are projected to increase over the period during which APS's rates are expected to be in effect. It is not reasonable to rely on current Treasury bond yields as the risk-free rate when those interest rates are not expected to persist during the period in which the rates set in this proceeding will be in effect. Similarly, Mr. Cassidy's historical MRP is based on historical data from 1978-2019, when average interest rates on 20-year government bonds were well above current levels. Mr. Cassidy's use of historical data to compute the MRP fails to recognize the inverse relationship between interest rates and the MRP and causes his CAPM approach to understate the cost of equity for APS.

- Mr. Cassidy's Comparable Earnings analysis produces ROE estimates from 9.50 percent to 10.00 percent. He selects the midpoint of this range of 9.75 percent as his Comparable Earnings estimate and places 40 percent weight on that result in his ROE recommendation. Mr. Cassidy's Comparable

Earnings analysis includes both historical and projected returns on equity for his proxy group companies. I disagree with the use of historical returns because the cost of equity analysis is intended to be forward-looking. My Expected Earnings analysis considers projected ROEs for the proxy group companies, which are a good indication of the returns that investors are expecting to receive from these companies over the three-to-five year period covered by the Value Line data.

- Although Mr. Cassidy devotes many pages of his testimony to discussing the negative economic effects of the COVID-19 pandemic, Mr. Cassidy's recommendation to lower APS's currently authorized ROE by more than 125 basis points is based on the use of recent historical market data (interest rates, stock prices, dividend yields, growth rates, etc.) and fails to reflect the uncertainty and volatility that has characterized capital markets in 2020. As shown by the Beta coefficients that Mr. Cassidy has used in his CAPM analysis, the relative risk of the proxy group companies has increased significantly as compared to the period before COVID-19. This is the only model input that Mr. Cassidy has used which appropriately reflects the elevated risk and uncertainty for utility stocks in the current market environment. For that reason, his ROE analysis and recommendation substantially understates the cost of equity for APS and should not be relied upon by the Commission to establish the authorized ROE for the Company in this proceeding.

Q. PLEASE SUMMARIZE YOUR RESPONSE TO RUCO WITNESS MR. CASSIDY WITH RESPECT TO THE FVI AND THE FVROR.

A. Mr. Cassidy recommends a return on the FVI of 0.00 percent, even though he indicates that RUCO's calculated FVI is 0.28 percent. In Arizona, the FVI is intended to provide the regulated utility with a return on the incremental portion of rate base above the original cost. A zero percent return on the FVI fails to take into consideration that investors would not provide additional capital to APS at no cost. As explained in my Direct Testimony, the cost of that incremental capital lies somewhere between the risk-free rate and the cost of equity. Using reasonable inflation estimates, based on my updated analysis, my recommended return on the FVI is 1.28 percent. APS is requesting a cost rate on the FVI of 0.80 percent, which is conservative, and would result in a FVROR of 5.51 percent.

Q. PLEASE SUMMARIZE YOUR RESPONSE TO FEA WITNESS MR. WALTERS AS IT RELATES TO THE AUTHORIZED ROE FOR APS.

A. As shown in Figure 1, the ROE results presented by Mr. Walters range from 8.31 percent to 12.16 percent. Mr. Walters' recommended ROE of 9.30 percent is 70 basis points below the 10.00 percent return that was authorized for APS in August 2017[12], and it is approximately 35 basis points below the average equity returns that have been authorized for integrated electric utilities nationwide since January 2018 (9.65 percent). Thus, Mr. Walters' recommended ROE is not a reasonable estimate of the cost of equity for APS. Mr. Walters and I disagree on the following six topics:

- I disagree with Mr. Walters regarding which analytical approaches to use and how much weight to put on their results:

  My recommended ROE (10.15 percent in my Direct Testimony, updated to 10.00 percent in this Rebuttal Testimony) is largely based on my DCF model and CAPM results. I use Expected Earnings and Bond Yield Plus Risk Premium analyses to corroborate my DCF and CAPM results.[13]

[12] *Ibid*.

[13] It is important to note that the Company has reduced its requested ROE from 10.15 percent to 10.00 percent in its Rebuttal Testimony.

In contrast, Mr. Walters places equal weight on the number he deems to be the summary result from each of three analyses: DCF, CAPM, and Bond Yield Plus Risk Premium. He does not conduct an Expected Earnings analysis. His DCF and Bond Yield Plus Risk Premium results receive two-thirds weight in his final recommendation, despite the fact that they fall at the very low end of the range of authorized ROEs for integrated electric utilities over the past three years (as shown below, in Figure 2).

- I disagree with several of Mr. Walters' assumptions in his DCF models, including the "sustainable" growth rates used in one version of his single-stage DCF model and in his multi-stage DCF model. Based on his DCF models, Mr. Walters estimates the investor required ROE at 9.10 percent; meanwhile, I estimate a reasonable ROE range up to 95 basis points higher (as shown below, in Figure 3).

- I fundamentally disagree with Mr. Walters' methodology for his Bond Yield Plus Risk Premium analysis. Mr. Walters's methodology involves manipulating long-term averages, to estimate an investor-required ROE at 9.00 percent. Using a more sophisticated approach involving regression analysis, I estimate the ROE at a level up to 96 basis points higher (as shown below, in Figure 3).

- I disagree with Mr. Walters' assumptions for the risk-free interest rate, proxy company Beta, and MRP in the CAPM. Using the CAPM, Mr. Walters estimates the required ROE at 9.60 percent; given my inclusion of a longer-term interest rate scenario, appropriately excluding outdated past-year Betas and non-comparable high-frequency Betas, and my use of a MRP derived from forward-looking market data, I estimate the ROE at a level up to 307 basis points higher (as shown below, in Figure 3).

- I disagree with Mr. Walters' characterization of the current economic context for determining APS's authorized ROE. Specifically, I disagree regarding the direction of recent trends in utility credit ratings, and the relevance of a recent downward revision to the credit outlook for APS. I also disagree as to whether utilities can be adversely affected by ROEs that are too low, and whether high stock prices guarantee proper access to capital.

- Finally, I disagree with Mr. Walters' assessment of APS's business risk. Mr. Walters considers APS less risky than its proxy group, while I consider the Company's risk to be above the average of the proxy group. I further disagree with Mr. Walters that all risks are already reflected in credit ratings or that investors only deserve compensation for market risk.

Q. PLEASE SUMMARIZE YOUR RESPONSE TO AECC WITNESS MR. HIGGINS WITH RESPECT TO THE APPROPRIATE ROE FOR APS.

A. Mr. Higgins does not recommend a specific ROE for APS. Rather, he defers to the analysis of Staff and RUCO and suggests that the Commission should examine the Company's request in light of recent ROE awards for integrated electric utilities approved by commissions nationwide.[14] Mr. Higgins testifies that the median authorized ROE for vertically-integrated electric utilities for the twelve months ending June 30, 2020 was 9.75 percent.[15] Mr. Higgins does not take into consideration the range of those authorized returns, nor does he consider the comparative risk of APS and the companies in his data set. Mr. Higgins does not provide his own recommendation on the appropriate cost of equity and ultimately

[14] Direct Testimony of Kevin C. Higgins, at 32 (Oct. 2, 2020).
[15] *Ibid*.

includes an ROE of 9.75 percent in his revenue requirement "pending further information being presented into the record by other parties."[16]

Q. HAVE YOU UPDATED YOUR ROE ANALYSES AND RANGE OF RESULTS IN REBUTTAL?

A. Yes. I have updated my analytical results based on market data as of September 30, 2020, as discussed in Section IV of my Rebuttal Testimony. Based on these updated results, I recognize that the short-term results of certain models have declined to some degree since the filing of my Direct Testimony. While interest rates on government and utility bonds have decreased since the filing of my Direct Testimony, I demonstrate that current interest rate conditions appear to be driven by short-term events including the COVID-19 pandemic and the policy response from the Federal Reserve and U.S. Congress to mitigate the economic effect of COVID-19 and to stabilize financial markets. Over the longer-term, investors continue to expect higher interest rates on government and corporate bonds. In addition, since mid-February 2020, equity markets have been characterized by uncertainty and volatility, as demonstrated by indicators such as elevated volatility in stock prices and substantial increases in Beta coefficients for regulated utilities. These factors suggest that, while interest rates have declined, the cost of equity has increased.

My updated range of results is from 9.75 percent to 10.25 percent, and the Company has reduced its requested ROE from 10.15 percent to 10.00 percent. Considering the risk factors for APS, an authorized return of 10.00 percent is conservative. While the analytical results of ROE estimation models provide a starting point in establishing a just and reasonable ROE, it is also important to consider other factors, including Company-specific risks, capital market conditions, and the capital attraction and comparable return standards.

[16] *Ibid*.

III. AUTHORIZED RETURNS IN OTHER JURISDICTIONS

Q. SEVERAL OF THE OPPOSING ROE WITNESSES REFERENCE ROE AWARDS IN OTHER JURISDICTIONS. DO YOU AGREE THAT THESE RETURNS PROVIDE A PRACTICAL BENCHMARK FOR ASSESSING THE REASONABLENESS OF ROE RECOMMENDATIONS?

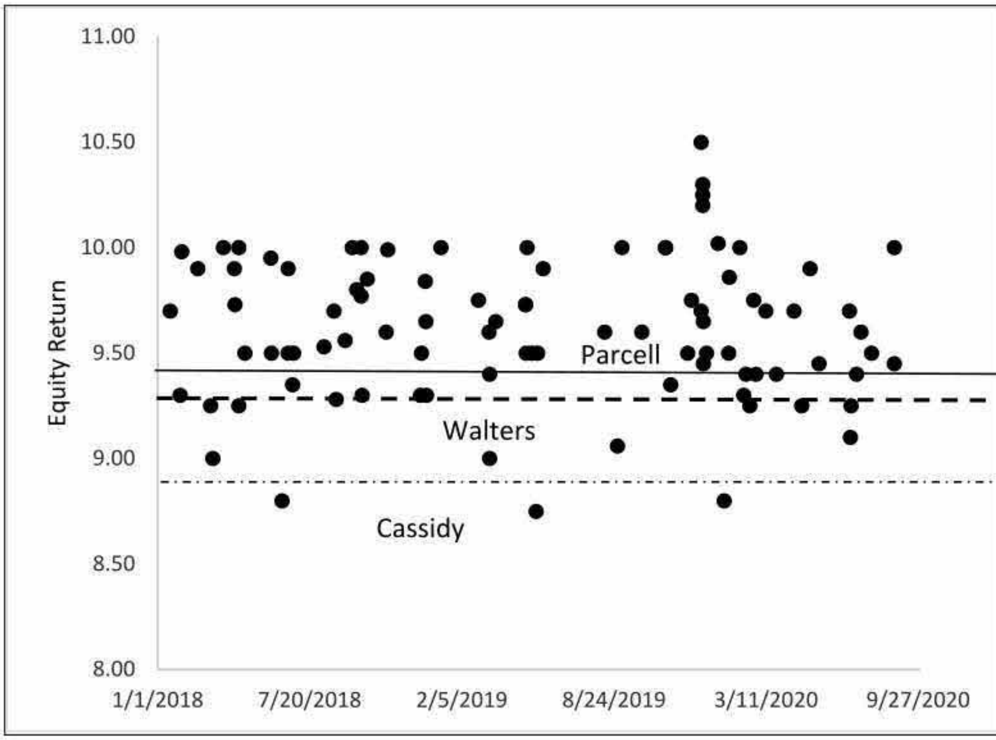
A. Yes, I do. Authorized ROEs in other jurisdictions provide a useful benchmark because investors use these returns in establishing their future return requirements, and these data can assist the Commission in assessing the overall reasonableness of the ROEs proposed by the witnesses in this proceeding. These authorized returns also send an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, financial growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk, investors have the incentive to direct their capital to those investments. Thus, an authorized ROE significantly below authorized ROEs in other jurisdictions could inhibit APS's ability to attract capital on reasonable terms for investment in Arizona.

Q. HOW DO THE ROE RECOMMENDATIONS OF THE OPPOSING ROE WITNESSES COMPARE TO THE ALLOWED ROES FOR OTHER INTEGRATED ELECTRIC UTILITIES?

A. As shown in Figure 2, the ROE recommendations of Mr. Cassidy (8.74 percent), Mr. Walters (9.30 percent), and Mr. Parcell (9.40 percent) are well below the vast majority of authorized ROEs for vertically-integrated electric utilities since January 2018.[17]

[17] Mr. Higgins does not provide any cost of capital analyses and instead defers to Staff and RUCO for that analysis. Mr. Higgins relies on the national average of authorized ROEs which he states is 9.75 percent as of June 2020 in his AECC's recommended revenue requirement.

Figure 2: Authorized ROEs for Integrated Electric Utilities (January 2018 – September 2020)[18]



Q. WHY IS APS'S REVISED ROE REQUEST OF 10.00 PERCENT JUST AND REASONABLE COMPARED TO THE RECENTLY AUTHORIZED RETURNS FOR INTEGRATED ELECTRIC UTILITIES IN THE PAST YEAR?

A. As discussed in my Direct Testimony, APS has substantial risk related to its ownership of nuclear generation assets. In addition to the operational and safety risks identified in my Direct Testimony, a recent equity analyst report indicates that, "[f]or economic reasons, several nuclear plants have been retired and we expect that more will be, although a handful of plants have been rescued from early retirement through state legislation in New Jersey, New York and Illinois."[19]

[18] Source: SNL Financial. The 8.75 percent authorized ROE was for Otter Tail Power Company in a May 2019 decision; it is important to note that, in that case, all of the contested rate case issues were settled by the parties with the exception of the authorized ROE, which was the only fully litigated issue.

[19] CFRA, S&P Global Market Intelligence, Pinnacle West Capital Corporation Stock Report, October 10, 2020.

Attachment AEB-10DR to my Direct Testimony shows that nuclear generation represents more than 35 percent of APS's generation portfolio. Since January 2019, the average authorized ROE for integrated electric utility companies with nuclear generation has been 9.87 percent, while the average authorized ROE for integrated electric utility companies without nuclear generation has been 9.57 percent. For that reason, I conclude that it is just and reasonable for APS's authorized ROE to be set at a level higher than the 9.65 percent average of authorized ROEs for integrated electric utilities since January 2019.

Q. WHAT IS YOUR CONCLUSION REGARDING THE APPROPRIATE COST OF EQUITY FOR THE COMPANY?

A. While the average authorized ROE for integrated electric utilities has declined, there is variability in authorized ROEs. Based on the risk factors identified for APS, it is appropriate to set the ROE at least near the mean of the analytical results. As discussed earlier, based on my updated analyses, my revised range of results is between 9.75 percent and 10.25 percent as compared with my previous range of 10.00 percent to 10.50 percent in my Direct Testimony. This revised range takes into consideration the declining interest rate environment that has prevailed in 2020 since the analysis in my Direct Testimony was performed, while continuing to reflect investors' view that yields on government and corporate bonds will move higher over the longer-term, and the uncertainty and volatility that has characterized financial markets in 2020. APS's requested ROE of 10.00 percent (reduced from 10.15 percent) is reasonable based on the results of the ROE estimation methodologies, the recently authorized returns for vertically integrated electric utilities, company-specific risk factors and investors' expectation of market conditions over the period that rates will be in effect. ROEs at the levels proposed by the Opposing ROE witnesses are not reasonable and do not meet the comparable return standard established in *Hope* and *Bluefield* for a fair return.

IV. UPDATED ROE ANALYSIS

Q. HAVE YOU UPDATED YOUR ROE ANALYSES?

A. Yes, as shown in Attachments AEB-1RB through AEB-7RB, I have updated the ROE analyses contained in my Direct Testimony using market data through September 30, 2020. I have continued to exclude results below 7.00 percent because such returns do not provide a sufficient risk premium above the long-term debt cost to compensate equity investors for the risks associated with ownership. Figure 3 below summarizes the results of my updated analyses.

Figure 3: Summary of Updated Analytical Results[20]

Constant Growth DCF			
	Mean Low	**Mean**	**Mean High**
30-Day Average Price	8.52%	9.20%	10.05%
90-Day Average Price	8.41%	9.08%	9.94%
180-Day Average Price	8.23%	8.91%	9.76%
Capital Asset Pricing Model			
	Current Risk-Free Rate (1.42%)	**2020-2021 Projected Risk-Free Rate (1.64%)**	**2022-2026 Projected Risk-Free Rate (3.00%)**
Market Return sourced from Bloomberg			
Bloomberg Beta	11.23%	11.27%	11.52%
Value Line Beta	11.93%	11.96%	12.13%
Market Return sourced from the S&P Earnings and Estimates Report			
Bloomberg Beta	11.74%	11.78%	12.03%
Value Line Beta	12.47%	12.50%	12.67%
Bond Yield Plus Risk Premium			
Bond Yield Plus Risk Premium	9.29%	9.38%	9.96%
Expected Earnings Analysis			
Value Line 2023-2025	10.05%		

[20] In my updated analysis, I rescreened the proxy companies used in my Direct Testimony. Applying the same screening criteria used in my Direct Testimony, there are four companies that were excluded from my updated results: FE, PPL, DTE and SO.

Q. HAVE YOU ALSO UPDATED YOUR CALCULATION OF THE RETURN ON THE FVI AND THE RESULTING FVROR FOR APS?

A. Yes. I have updated my calculation of the FVI cost rate and the FVROR in Attachments AEB-8RB and AEB-9RB. As shown in those attachments, my updated calculation of the real risk-free rate is 1.28 percent. APS is requesting a FVI cost rate of 0.80 percent in rebuttal, which is conservative. Using a FVI cost rate of 0.80 percent, and the Company's updated requested ROE of 10.00 percent, the resulting FVROR for APS is 5.51 percent.

V. <u>CAPITAL MARKET CONDITIONS AND THEIR EFFECT ON THE COST OF EQUITY FOR APS</u>

Q. THE OTHER ROE WITNESSES IMPLY THAT THE DECLINING INTEREST RATE ENVIRONMENT SUPPORTS A SUBSTANTIAL REDUCTION IN THE AUTHORIZED ROE FOR APS IN THIS PROCEEDING.[21] DO YOU AGREE?

A. No, I do not. Government bond yields are only one of many factors that equity investors consider in determining their return requirements. It is important to view current Treasury bond yields in the context of conditions in the economy and capital markets. It would not be reasonable for the Commission to consider only the decline in 30-year Treasury bond yields, without also considering the recent market conditions that have contributed to that decline. Further, there are reasons to believe that the recent decline in Treasury bond yields is not representative of the longer-term trend in government and corporate bond yields. Rather, those lower interest rates are directly attributable to the COVID-19 pandemic. The economic effects of the measures used to contain COVID-19 have caused the Federal Reserve to reduce the federal funds rates and take additional measures to support the U.S. economy and provide liquidity and stability in financial markets. These are short-

[21] *See*, for example, Direct Testimony of David C. Parcell, at 9-16, Direct Testimony of John A. Cassidy, at 14-22, Direct Testimony of Christopher C. Walters, at 13-17.

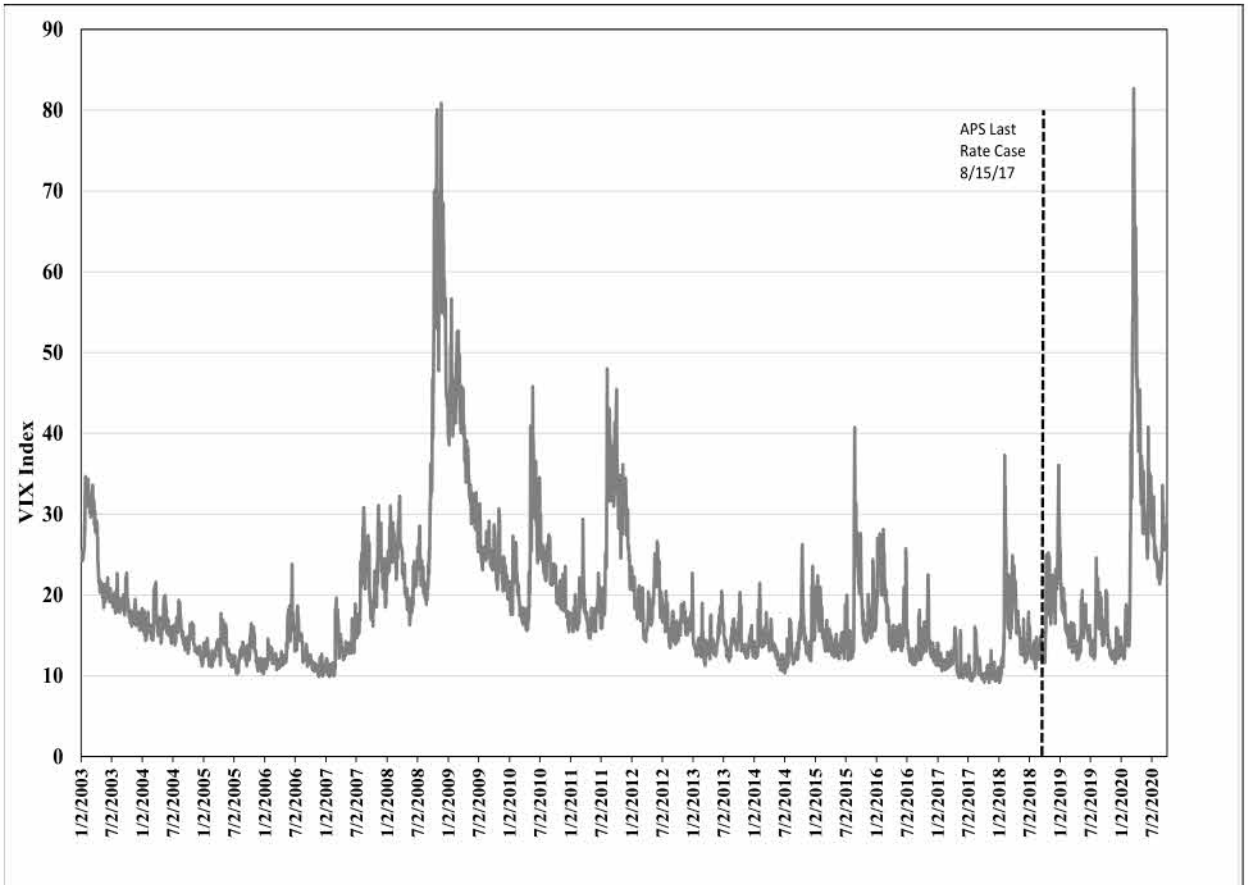
term events that have little to do with the longer-term trend in bond yields or equity costs.

Q. HOW HAVE CAPITAL MARKET CONDITIONS CHANGED SINCE THE FILING OF YOUR DIRECT TESTIMONY IN OCTOBER 2019?

A. Capital market conditions have been extremely volatile in 2020 due to the economic effects of the COVID-19 pandemic, as the measures used to contain COVID-19 have forced the U.S. economy into a recession. As a result, volatility has increased to levels not seen since the Great Recession of 2008/09. Figure 4 shows the Chicago Board Options Exchange (CBOE) Volatility Index (VIX). The VIX measures investors' expectations of volatility in the S&P 500 over the next 30 days. As shown in Figure 4, as a result of the pandemic, the VIX has reached levels not seen since the Great Recession of 2008/09. For example, the VIX was 82.69 on March 16, 2020. The VIX had not reached 80.00 since November 2008; it is important to note that the highest level reached during the Great Recession of 2008/09 was 80.86. This indicator shows that COVID-19 has caused an increase in the level of uncertainty and volatility in the market, even greater than during the Great Recession of 2008/09.

Furthermore, the VIX as of September 30, 2020 is much higher than it was at the time of the Commission's decision in APS's last rate case. Although volatility in equity markets declined to some extent from May through August, it remained well above the long-term median level over the past 20 years. In addition, as of the beginning of September 2020, the VIX once again increased above 30.00 providing further support for the fact that financial markets continue to face elevated uncertainty.

Figure 4: CBOE VIX (January 2003 – September 2020)[22]

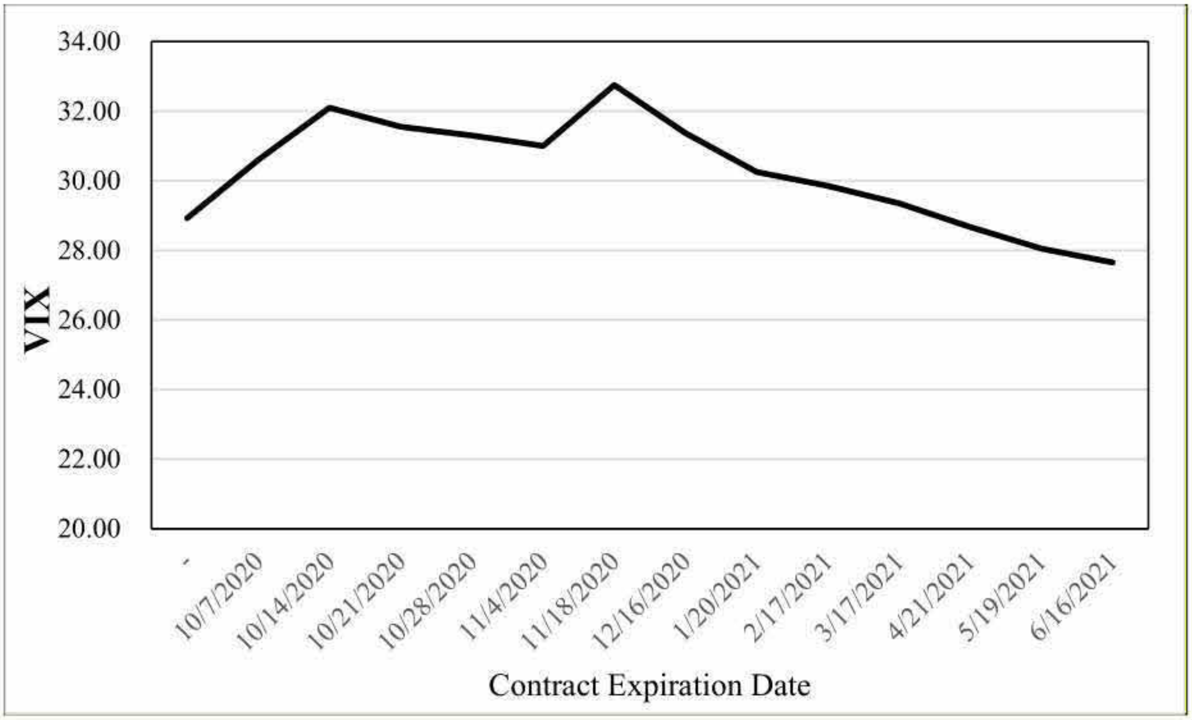


Q. WHAT ARE INVESTORS' EXPECTATIONS REGARDING THE VIX OVER THE NEAR-TERM?

A. The VIX futures reflect investors' views regarding the value of the VIX for different expiration dates in the future. As shown in Figure 5, investors expect the VIX to remain at levels that exceed 25.00 at least through June 2021. Therefore, investors expect increased volatility and uncertainty to persist over the near-term as the economy recovers from the economic effects of the COVID-19 pandemic.

[22] Source: Bloomberg Professional.

Figure 5: CBOE VIX Futures as of September 30, 2020



Q. WHAT STEPS HAVE THE FEDERAL RESERVE AND THE U.S. CONGRESS TAKEN TO STABILIZE FINANCIAL MARKETS AND SUPPORT THE ECONOMY?

A. In response to the economic effects of COVID-19, the Federal Reserve decreased the federal funds rate twice in March 2020, resulting in a target range of 0.00 percent to 0.25 percent and also announced plans to increase its holdings of both Treasury and mortgage-backed securities.[23] In addition, on March 23, 2020, the Federal Reserve began expansive programs to support credit to large employers: the Primary Market Corporate Credit Facility (PMCCF) to provide liquidity for new issuances of corporate bonds; and the Secondary Market Corporate Credit Facility (SMCCF) to provide liquidity for outstanding corporate debt issuances.

[23] Direct Testimony of Ann E. Bulkley, at 20-21.

Further, the Federal Reserve supported the flow of credit to consumers and businesses through the Term Asset-Backed Securities Loan Facility (TALF).[24]

In addition to the Federal Reserve's response, the U.S. Congress has also passed fiscal stimulus programs. On March 27, 2020, the Coronavirus Aid, Relief, and Economic Security (CARES) Act was signed into law, which is a large fiscal stimulus package aimed at also mitigating the economic effects of the coronavirus. While these expansive monetary and fiscal programs have provided for greater price stability, as shown in Figure 4 and Figure 5 above, the VIX remains well above long-term historical levels and is expected to remain above long-term historical levels over the near-term.

Q. HOW DO THE FEDERAL RESERVE'S RECENTLY ANNOUNCED PROGRAMS AFFECT THE ECONOMY AND FINANCIAL MARKETS?

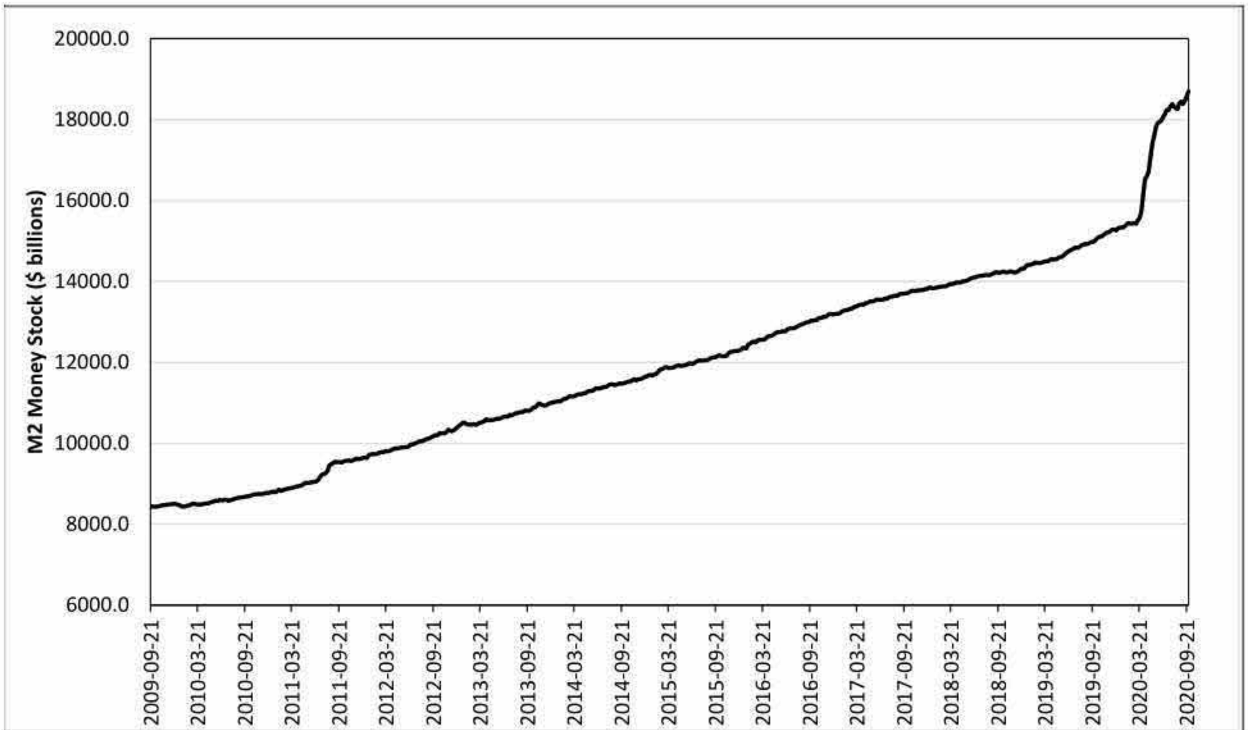
A. These programs allow the Federal Reserve to purchase government bonds and corporate bonds from banks. The banks then receive cash from the Federal Reserve, which results in an expansion of the money supply. This increase in the money supply keeps interest rates low and increases the ability of banks to lend to consumers and businesses. Continued access to capital is particularly important in current market conditions because it allows companies to offset the negative effect of COVID-19 on business operations. As shown in Figure 6, the programs enacted by the Federal Reserve have resulted in an unprecedented expansion of the money supply as measured by M2[25] in recent months. That expansion has been much greater than the increase seen following the Federal Reserve's response to the Great Recession of 2008/2009. This response from the Federal Reserve again

[24] Federal Reserve Board Press Release, "Federal Reserve announces extensive new measures to support the economy," March 23, 2020.

[25] M2 is defined by the Federal Reserve as follows: M2 includes a broader set of financial assets held principally by households. M2 consists of M1 plus: (1) savings deposits (which include money market deposit accounts, or MMDAs); (2) small-denomination time deposits (time deposits in amounts of less than $100,000); and (3) balances in retail money market mutual funds (MMMFs).

demonstrates the level of intervention that has been necessary to attempt to stabilize the markets over this period, suggesting greater market risk at this time than in 2017 when APS's currently-authorized ROE was approved.

Figure 6: M2 Money Stock – September 2009 – September 2020[26]



Q. HAVE THE OPPOSING ROE WITNESSES CONSIDERED HOW THE EQUITY MARKET HAS RESPONDED TO THE UNPRECEDENTED INTERVENTION BY THE FEDERAL RESERVE?

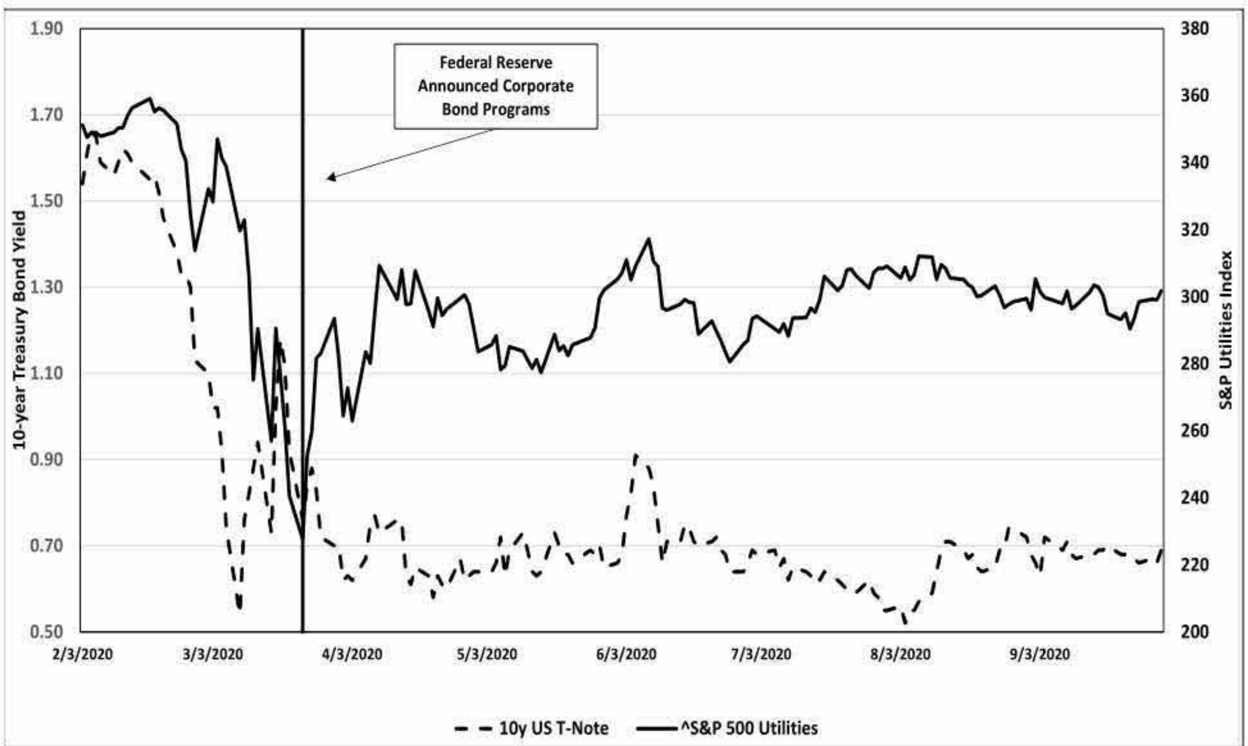
A. No, they have not. As discussed above, the Federal Reserve's expansive programs greatly increased the money supply, which resulted in lower borrowing costs for corporate firms and thus continued access to the capital needed to offset the economic effects of COVID-19. As a result, interest rates have remained low, and stability has been restored in the corporate bond market. For investors, this led to allocating more funds to equities. As shown in Figure 7, while the yield on the 10-

[26] Board of Governors of the Federal Reserve System (US), M2 Money Stock [M2], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/M2, October 8, 2020.

year Treasury bond has remained relatively stable in the range of 0.52 percent to 0.91 percent between March 23, 2020 and September 30, 2020, the S&P Utilities Index increased dramatically in the days immediately following the Federal Reserve's announcement on March 23, 2020.

Therefore, the policies of the Federal Reserve, while resulting in stability in the bond markets, have resulted in inflated equity prices, as investors search for higher returns given the current low interest rate environment. Thus, I do not agree that current share prices represent a reasonable indicator of the share prices that will persist over the near-term.

Figure 7: 10-year U.S. Treasury Yield and S&P Utilities Index



Q. HAVE RATING AGENCIES COMMENTED ON THE RECENT DECLINE IN BOND YIELDS AND THE ANTICIPATED EFFECT ON THE AUTHORIZED ROES FOR UTILITIES?

A. Yes. In April 2020, Moody's noted that it expects regulators to be hesitant to reduce authorized ROEs in response to the COVID-19 pandemic-related decline in the yield on 30-year Treasury bonds. Specifically, Moody's commented:

> As a result of the economic fallout from the coronavirus outbreak, the rate on the 30-year T-bill has declined significantly, as shown in Exhibit 2. Assuming utilities continue to earn the average 670 bps spread over the 30-year T-bill, this would suggest that there will be a great deal of pressure on authorized returns. **However, we think regulators will be hesitant to significantly reduce allowed returns given the uncertain market environment and the likely delays in adjudicating rate cases because of social distancing mandates and other issues associated with the coronavirus** (see "Regulated Electric, Gas and Water Utilities – US: Coronavirus outbreak delays rate cases, but regulatory support remains intact"). This may lead to the widest spread between the authorized ROE and the 30-year T-bill in at least the past two decades. Utilities with a formula driven approach to setting ROEs may be hurt far more quickly as their ROE's are adjusted automatically. We expect some of these utilities to appeal to regulators to either suspend or alter this formula based approach, at least temporarily.
>
> In contrast to the gradual, long-term decline in the 30-year T-bill illustrated in Exhibit 1, the year-to-date decline in the yield has been more abrupt, influenced by the plunge in economic activity at the end of the first quarter. We expect US GDP to undergo a sharp 4.5% contraction in the first half of the year, before finishing full-year 2020 down 2.0% and recovering in 2021 with 2.3% growth (see "Global Macro Outlook 2020-21 [March 25, 2020 Update]: The coronavirus will cause unprecedented shock to the global economy"). Given the continued uncertainty over efforts to contain the coronavirus outbreak, there is significant downside risk to our macroeconomic forecast. But if there were to be a material snapback in growth, we would expect interest rates to follow suit.[27]

[27] Moody's Investors Service, "Regulated Electric and Gas Utilities – US: Continued decline in ROEs to heighten pressure on financial metrics," April 17, 2020, at 3 (emphasis added).

Q. MR. CASSIDY TESTIFIES THAT INVESTMENT RETURNS ON BOTH STOCKS AND BONDS ARE EXPECTED TO DECLINE FROM HISTORICAL LEVELS.[28] WHAT IS YOUR RESPONSE?

A. As the basis for this statement, Mr. Cassidy cites a May 2016 report from McKinsey and Company that analyzes historical investment returns for stocks and bonds over the 30-year period from 1985-2014. McKinsey observes that returns over this period were well above historical average levels and argues that the conditions that contributed to these above-average returns are not likely to be repeated.

In reviewing this report, I observe that the prospective equity returns that McKinsey was projecting from 2016-2035 under the "growth recovery" scenario are similar to those over both the 100-year period from 1915-2014 and the 50-year period from 1965-2014. Actual equity returns for the S&P 500 from 2016-2019 have been substantially higher than those projected by McKinsey, while S&P's Earnings and Estimates Report is projecting a total market return for the S&P 500 companies of 14.05 percent per year over the next five years. Therefore, it appears the McKinsey report is significantly understating the actual and expected returns of the broader market.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE EFFECT OF RECENT MARKET VOLATILITY AND THE POLICIES OF THE FEDERAL RESERVE ON THE COST OF EQUITY FOR APS?

A. The risks in the current market environment were not present in the data in APS's last rate case. Given the uncertainty and volatility that has characterized capital markets in 2020, it is reasonable that equity investors would now require a higher return on equity to compensate them for the additional risk associated with owning common stock under these market conditions. Therefore, relying on current market

[28] Direct Testimony of John A. Cassidy, at 31-34.

data would likely suggest that the cost of equity has increased since the Commission approved the settlement in APS's last rate proceeding. As a result, APS's requested ROE of 10.00 percent is a reasonable, if not conservative, estimate of the ROE in the current market environment. Furthermore, based on these data, the Opposing ROE witnesses' recommendations to reduce APS's ROE to reflect current market conditions are unsupported.

Q. MR. WALTERS COMMENTS ON THE HIGH VALUATIONS IN THE UTILITIES SECTOR.[29] WHAT IS YOUR RESPONSE?

A. As I discussed in my Direct Testimony, and as Mr. Walters also notes, the valuations of public utilities have increased well above historical average levels in recent years, as demonstrated by their elevated Price-to-Earnings (P/E) ratios.[30] However, Mr. Walters contends that these high valuations, which are reflected in his data on market-to-book ratios, are an indication that authorized returns for utilities are sufficient to support market prices that at least exceeded book value.[31] However, he fails to recognize how these high valuations affect the results of his DCF models.

The DCF approach to ROE estimation generally produces reasonable and reliable estimates of the cost of equity for companies in stable, mature industries, such as regulated utilities; however, the results from DCF models are being distorted by the high valuations and low dividend yields of utilities. Even though utility share prices have declined from their peak in February 2020, the P/E ratios remain higher than historical average levels over the past decade, while dividend yields remain lower than historical average levels.

[29] Direct Testimony of Christopher C. Walters, at 36.
[30] Direct Testimony of Ann E. Bulkley, at 15-16.
[31] Direct Testimony of Christopher C. Walters, at 36.

Q. HAVE EQUITY ANALYSTS COMMENTED ON THE VALUATIONS OF UTILITY STOCKS IN RECENT MONTHS?

A. Yes. Several equity analysts have recognized that utility stock valuations remain very high relative to historical levels even after the decline in share prices that occurred as a result of the economic effects of COVID-19. For example, Barron's noted:

> Charles Fishman, a utility analyst at Morningstar, points out that "utility valuations in February were at record highs," and that "commercial and industrial electricity demand reductions and delay in investment due to the pandemic" have weighed on these stocks as well.
>
> In May, power demand in the U.S. was down 8% year over year, according to Morgan Stanley. That follows a 5% drop in April.
>
> But even after lackluster performance recently, utility shares still aren't cheap. The stocks in the Utilities Select Sector SPDR ETF trade at about 19 times their current fiscal year profit estimates, according to FactSet. That's above their five-year average of a little below 18 times.[32]

This implies that even after the economic effects of COVID-19 are considered, the ROE calculated using historical market data in the DCF model is still understating the forward-looking cost of equity.

Q. UTILITIES TRADITIONALLY HAVE BEEN A SAFE HAVEN FOR INVESTORS DURING PERIODS OF MARKET VOLATILITY. HAS THIS BEEN TRUE DURING THE RECENT PERIOD OF VOLATILITY?

A. No, it has not. Contrary to the testimony of Mr. Walters, who expresses concern with the recent increase in Value Line Beta coefficients for electric utilities,[33] these stocks have not been a safe-haven for investors during the COVID-19 pandemic.

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[32] Strauss, Lawrence C. "Utility Stocks Aren't Acting Like The Havens They're Supposed Be. Here's Why." Utility Stocks Aren't Acting Like The Havens They're Supposed Be - Barron's, 12 June 2020, www.barrons.com/articles/utility-stocks-arent-acting-like-the-havens-theyre-supposed-be-51591979393.

[33] Direct Testimony of Christopher C. Walters, at 43.

To this point, Charles Schwab recently rated the Utilities sector as "Underperform," noting:

> The Utilities sector has tended to perform better when growth and trade concerns resurface, and to underperform when those concerns fade. That's partly because of the sector's traditional defensive nature-people need water, gas and electric services during all phases of the business cycle-and these are domestic goods and services, so it has very little international exposure.
>
> However, amid the drop in stocks in February and March, the historically low-equity-beta Utilities sector simply didn't play its traditional relative safe-haven role. The sharp drop in interest rates would normally be expected to provide relative support to this sector, which relies on high levels of debt and tends to pay relatively high dividends-often an attraction for investors when yields on fixed income investments are low. However, there were unique circumstances that outweighed these historical relationships.
>
> For one thing, because some investors had already been reaching for yield before the crisis began, the high-dividend-paying Utilities sector had been bid up to record-high valuation levels. Even underperformance year-to-date hasn't fully reversed those relatively high valuations, so we're not confident the sector will return to its defensive roots if markets sell off again.[34]

Q. HOW HAS THE UTILITIES SECTOR PERFORMED IN 2020 RELATIVE TO THE S&P 500?

A. The utilities sector has been one of the worst performing market sectors in 2020, having declined by 10.77 percent from the mid-February peak as compared to a 3.30 percent increase for the S&P 500.[35] The only market sectors that have underperformed utilities in 2020 are financials (down 20.46 percent) and energy (down 60.27 percent). The other eight S&P market sectors are either down slightly from their peak or are at or near record highs.

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[34] Charles Schwab, Utilities Sector Rating: Underperform, October 15, 2020.
[35] Data as of October 13, 2020.

Q. WHAT IS CONTRIBUTING TO THE RELATIVE UNDER-PERFORMANCE OF THE UTILITIES SECTOR?

A. The relative underperformance of the utilities sector is partly attributable to the fact that demand for electricity decreased as non-essential businesses in many parts of the country were forced to close for a period in March through May, and began to re-open slowly in June and July. While electricity demand is typically inelastic, the load data demonstrates that utilities have been affected by COVID-19. In October 2020, the U.S. Energy Information Administration (EIA) forecast that overall electricity sales would decrease by 2.2 percent in 2020 compared to 2019. Commercial sales are projected to decline by 6.2 percent this year due to COVID-19 mitigation efforts, electricity sales to the industrial sector are expected to fall by 5.6 percent, while residential electricity sales are projected to increase by 3.2 percent.[36] The underperformance of the utilities sector is an indication that it has become more difficult for utilities to retain and attract capital in the current economic environment.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE RECENT VALUATIONS OF UTILITIES AND THE EFFECT ON THE COST OF EQUITY FOR APS IN THIS PROCEEDING?

A. While the share prices of utilities have declined in response to the economic effects of the COVID-19 pandemic, current utility valuations are still well above the long-term average. The current high valuations result in low dividend yields for utilities, which means that the DCF model using recent historical stock price data likely underestimates investors' required returns. Alternatively, my CAPM analysis includes estimated returns based on near-term and longer-term projected interest rates, considers Beta coefficients that reflect the fact that analysts expect utilities to trade similar to the market over the near-term, and relies on a forward-looking

[36] U.S. Energy Information Administration: Short-Term Energy Outlook, October 6, 2020, at 3-4.

estimate of the market return. It is important to consider the results of each of the models to reflect investors' expectations of market conditions over the period that the rates established in this proceeding will be in effect.

Q. HAVE THE OPPOSING ROE WITNESSES CONSIDERED THE EFFECTS OF THE TCJA WHEN DEVELOPING THEIR RECOMMENDED ROE?

A. No, they have not. Because the Opposing ROE witnesses did not consider the TCJA, it appears each witness believes that any effect of the TCJA is already taken into consideration in the share prices that are used in the DCF model. As discussed in my Direct Testimony, it is reasonable to expect that investors have reviewed the reports published by the credit rating agencies and are therefore considering the effects of the TCJA.[37] However, utilities are still working with regulators to determine appropriate solutions to mitigate the effect of the TCJA on cash flows. Moreover, as shown in Figure 8, Moody's has continued to downgrade utilities in 2019 and 2020 as a result of tax reform, which suggests that Moody's is continuing to evaluate the effect of the TCJA on the cash flows of individual utilities.

[37] Direct Testimony of Ann E. Bulkley, at 24-28.

Figure 8: Additional Moody's Credit Rating Downgrades since Direct Testimony

Utility	Rating Agency	Credit Rating before TCJA	Credit Rating after TCJA	Downgrade Date
Electric Transmission Texas	Moody's	Baa1	Baa2	3/24/2020
New Jersey Natural Gas Company	Moody's	Aa3	A1	3/18/2020
Consolidated Edison Company of New York	Moody's	A3	Baa1	3/17/2020
Consolidated Edison, Inc.	Moody's	Baa1	Baa2	3/17/2020
Washington Gas Light Company	Moody's	A2	A3	1/30/2020
Public Service Co. of North Carolina, Inc.	Moody's	A3	Baa1	1/30/2020
Wisconsin Power and Light Company	Moody's	A2	A3	12/11/2019
Wisconsin Gas LLC	Moody's	A2	A3	11/20/2019
Vectren Utility Holdings	Moody's	A2	A3	10/25/2019
Southern Indiana Gas & Electric Company	Moody's	A2	A3	10/25/2019
Indiana Gas Company	Moody's	A2	A3	10/25/2019
El Paso Electric Company	Moody's	Baa1	Baa2	9/17/2019
Questar Gas Company	Moody's	A2	A3	8/15/2019

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE EFFECT OF THE TCJA ON APS'S COST OF CAPITAL?

A. The issue with respect to the TCJA is not whether this policy has been internalized in the DCF model. Rather, the issue is how to consider this policy when determining the appropriate ROE for the Company from within the range of ROE results that are produced using all of the ROE estimation models. The TCJA has been identified by the credit rating agencies as credit negative due to the increase to the financial risk of the utilities sector. This is an important factor to consider in setting the appropriate ROE and equity ratio for APS.

VI. <u>RESPONSE TO STAFF WITNESS PARCELL</u>

Q. PLEASE SUMMARIZE STAFF WITNESS PARCELL'S ROE RECOMMENDATION.

A. Mr. Parcell recommends an ROE for APS of 9.40 percent based on the results of his DCF and Comparable Earnings analyses, which were supported by a Risk

Premium analysis. While Mr. Parcell also performed a CAPM analysis, his recommendation does not directly incorporate the results of that analysis. Mr. Parcell's recommended ROE is 60 basis points lower than the Company's currently authorized ROE of 10.00 percent. As support for his ROE recommendation, Mr. Parcell cites the low interest rate environment in recent years, which he contends has become the "new norm."[38]

Q. WHAT IS YOUR RESPONSE TO MR. PARCELL'S TESTIMONY AND RECOMMENDATION CONCERNING THE COST OF EQUITY?

A. Mr. Parcell's recommendation of 9.40 percent is unduly low in light of current and projected economic and capital market conditions discussed in Section V above, and is not consistent with recently-authorized ROEs for vertically-integrated electric utilities in other jurisdictions as summarized in Figure 2 above. Mr. Parcell's recommended ROE does not appear to rely on several of his analyses. Mr. Parcell indicates that the overall range of his results is from 6.40 percent to 10.00 percent, and within that range he establishes a recommended range of 9.30 percent to 9.50 percent. 9.30 percent is the high end of the range of his DCF results, and 9.50 percent is the midpoint of his CE analysis.[39] His recommendation of 9.40 percent is simply the midpoint of these values. Therefore, it appears that Mr. Parcell does not place any weight on the results of his CAPM analysis or his Risk Premium results. Furthermore, it is not clear whether Mr. Parcell has considered the full extent of APS's operating risks, particularly those related to its generation portfolio. In his most recent testimonies, Mr. Parcell's recommendations have been within a tight range (between 9.0 and 9.4 percent), despite large differences in operating risks among the subject utilities (i.e., water utilities, vertically integrated electric utilities with differing generation portfolios, etc.).

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[38] Direct Testimony of David C. Parcell, at 45.

[39] *Id.*, at 44.

Q. IS MR. PARCELL'S ROE RECOMMENDATION OF 9.40 PERCENT CONSISTENT WITH RETURNS FOR INTEGRATED ELECTRIC UTILITIES IN OTHER JURISDICTIONS ACROSS THE U.S.?

A. No, it is not. As shown in Figure 2, Mr. Parcell's ROE recommendation of 9.40 percent is in the lower half of the range of recent ROE awards for integrated electric utilities. In 2018-2020, the range of ROEs for vertically integrated electric utilities was 8.75 percent[40] to 10.50 percent, with an average return of 9.68 percent. Forward-looking economic and capital market conditions, as well as APS's additional business risks, support an authorized ROE above the proxy group average and higher than the average for integrated electric utilities nationwide. As discussed in my Direct Testimony, APS has higher risk associated with its generation portfolio compared to the companies in its proxy group, and it also has above average regulatory risk in Arizona.[41]

Q. MR. PARCELL SUMMARIZES GAS AND ELECTRIC UTILITY AUTHORIZED RETURNS FROM 2007 TO 2020 IN HIS TESTIMONY.[42] DOES THIS PROVIDE A REASONABLE BENCHMARK FOR APS'S AUTHORIZED RETURN?

A. No, it does not. Although I generally agree with Mr. Parcell's figures for electric and gas utility rate case averages since 2007, he has not attempted to distinguish between vertically integrated electric utilities and electric distribution utilities. Vertically integrated utilities have much more risk than pure transmission and distribution (T&D) utilities. The risks associated with owning generation assets include market risk, cost recovery risk, and regulatory risk associated with market forces, unplanned outages and maintenance, and new environmental requirements.

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[40] The 8.75 percent ROE was authorized for Otter Tail Power in a case that was fully settled, except for the ROE. Excluding the Otter Tail Power case, the lowest authorized ROE was 9.06 percent.

[41] Direct Testimony of Ann E. Bulkley, at 55-60.

[42] Direct Testimony of David C. Parcell, at 15-16.

As shown in Figure 9, authorized returns for vertically-integrated electric utilities have averaged between 35 and 76 basis points higher than returns authorized for T&D companies from 2014-2020. Mr. Parcell's recommendation does not reflect the additional risk of owning generation assets.

Figure 9: Authorized ROEs for State Jurisdictional Electric Utility Operations[43]

Year	All Electric	Distribution	Vertically Integrated	Difference
2014	9.76%	9.49%	9.94%	0.45%
2015	9.60%	9.17%	9.68%	0.51%
2016	9.60%	9.31%	9.67%	0.36%
2017	9.68%	9.43%	9.78%	0.35%
2018	9.56%	9.38%	9.76%	0.38%
2019	9.64%	9.37%	9.88%	0.50%
2020	9.44%	9.22%	9.98%	0.76%

Q. PLEASE DESCRIBE THE DIFFERENCES IN YOUR PROXY GROUP FROM THAT USED BY MR. PARCELL.

A. Mr. Parcell employs two proxy groups for purposes of his analysis. His first group includes electric utilities which meet the following criteria:

1. Market "cap" of $1 billion to $20 billion;
2. Common equity ratio of 40 to 60 percent;
3. Value Line Safety ranking of 1 to 2;
4. Moody's and S&P's bond ratings of A or BBB; and
5. Currently pay dividends and has not reduced dividends in the past five years.[44]

The second proxy group used by Mr. Parcell was the 14-company proxy group that I presented in my Direct Testimony.

[43] Source: S&P Global Market Intelligence.
[44] Direct Testimony of David C. Parcell, at 23.

A. *Constant Growth DCF Model*

Q. PLEASE SUMMARIZE MR. PARCELL'S CONSTANT GROWTH DCF ANALYSES.

A. Mr. Parcell performs a Constant Growth DCF analysis with several indicators of expected dividend growth, including:

1) Years 2015 to 2019 (five-year average) earnings retention, or fundamental growth (per Value Line);

2) Five-year average of historic growth in Earnings per Share (EPS), Dividends per Share (DPS), and Book Value Per Share (BVPS) (per Value Line);

3) Years 2020, 2021 and 2023 to 2025 projections of earnings retention growth (per Value Line);

4) Years 2017 through 2019 to 2023 through 2025 projections of EPS, DPS, and BVPS (per Value Line); and

5) Five-year projections of EPS growth (per First Call, Value Line and Zacks).[45]

The DCF return estimates from Mr. Parcell's analysis ranged from 6.6 percent to 9.3 percent. As a result of his analyses, Mr. Parcell believes a range of 8.7 percent to 9.3 percent, with a 9.0 percent mid-point, represents the DCF-derived ROE for the proxy group.[46]

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[45] *Id.*, at 26.
[46] *Id.*, at 27.

Q. IN HIS CRITIQUE OF YOUR ANALYSIS, MR. PARCELL STATES THAT "IT IS NEITHER REALISTIC NOR APPROPRIATE TO FOCUS ON A SINGLE GROWTH RATE FOR EACH PROXY COMPANY IN A DCF CONTEXT, ESPECIALLY WHEN ONE "CHERRY PICKS" THE HIGHEST GROWTH RATE FOR EACH COMPANY FROM AMONG THE DIFFERENT GROWTH RATE INDICATORS THAT REFLECT THE HIGHEST GROWTH RATE FOR EACH COMPANY."[47] HOW DO YOU RESPOND?

A. First, as explained in my Direct Testimony, it is important to note that my analysis considered the results of the DCF model using the lowest, the mean and the highest growth rates for each individual proxy company.[48] This analysis provides the full range of DCF results that may be considered by investors. Singling out only one end of that range of analysis is disingenuous.

Second, the Constant Growth DCF model is a forward-looking model that evaluates investors' required returns based on future cash flows. As such, the appropriate measure of growth is investors' expectations, not historical results. Furthermore, it is important to consider all expectations, the low, high and the mean result. Historical growth rates are less relevant because past growth may not reflect future growth potential. Furthermore, securities' analysts forecasted EPS growth rates incorporate historical performance to the extent the analysts believe that historical performance is relevant and applicable for the future. Additional consideration of historical growth rates provides no meaningful incremental information regarding the proxy companies' future growth potential and places unwarranted weight on historical events.

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[47] *Id.*, at 29.

[48] Direct Testimony of Ann E. Bulkley, at 42.

Q. DOES MR. PARCELL DISAGREE WITH THE EARNINGS GROWTH ESTIMATES IN YOUR CONSTANT GROWTH DCF MODEL?

A. Yes. Mr. Parcell suggests that my ROE recommendation is biased upward in a manner that inflates the return recommendation. He states that I "cherry pick" the highest growth rate for each company from among the different growth rate indicators.[49]

Q. WHAT IS YOUR RESPONSE?

A. As explained in my Direct Testimony, dividend growth can only be sustained by earnings growth.[50] Earnings are the fundamental determinant of a company's ability to pay dividends. Further, both dividends and book value per share may be directly affected by short run management decisions. As a result, dividend growth rates and book value growth rates may not accurately reflect a company's long-term growth. In contrast, earnings growth rates are not affected by short run cash management decisions and are the only forward-looking growth rates available on a consensus basis.

While Mr. Parcell criticizes my use of EPS growth projections as the measure of growth, it is in effect the sole growth rate that he also relies upon when establishing his ROE recommendation. As discussed previously, Mr. Parcell states that his recommended range for his ROE is based on the upper end of his DCF results of 9.30 percent and the midpoint of his CE analysis. As shown in Exhibit No. ___(DCP-1), Schedule 7 (at 5), the high end of Mr. Parcell's range, is based on my proxy group[51] and prospective EPS growth rates. Therefore, Mr. Parcell's criticism of my use of EPS growth rates is also disingenuous.

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[49] *Ibid.*

[50] Direct Testimony of Ann E. Bulkley, at 41.

[51] In each instance in my Rebuttal Testimony where I refer to Mr. Parcell's analysis using my proxy group, I am referring to the proxy group relied upon in my Direct Testimony.

Q. MR. PARCELL CITES A 2010 MCKINSEY & COMPANY STUDY AS WELL AS AN SEC REPORT FROM THE SAME YEAR TO WARN AGAINST RELYING UPON ANALYSTS' EPS GROWTH RATES. HOW DO YOU RESPOND?[52]

A. Mr. Parcell continues to reference a 2010 McKinsey study and an SEC Investor Alert in his testimony to support his claim of analyst bias; however, the evidence on the topic is far from clear and there are many conflicting opinions.[53] As I have noted in response to Mr. Parcell in other cases, the Global Analysts Research Settlement of 2003 (the "Global Settlement") served to remove all incentives for bias in the financial industry. Specifically, the Global Settlement required financial institutions to insulate investment banking from analysis, prohibited analysts from participating in "road shows," and required the settling financial institutions to fund independent third-party research. In addition, analysts covering the common stock of the proxy companies must certify that their analyses and recommendations are not related, either directly or indirectly, to their compensation.

Since the Global Settlement, a 2010 article in <u>Financial Analysts Journal</u>, for example, found that analyst forecast bias has significantly declined or disappeared entirely:

> Introduced in 2002, the Global Settlement and related regulations had an even bigger impact than Reg FD on analyst behavior. After the Global Settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. Although disentangling the impact of the Global Settlement from that or related rules and regulations aimed at mitigating analysts' conflicts of interest is impossible, forecast bias clearly declined around the time the Global Settlement was

[52] Direct Testimony of David C. Parcell, at 30-31.
[53] Mr. Parcell cited these same studies in his Direct Testimony filed in Docket No. E-01933A-15-0239, at 37.

announced. These results suggest that the recent efforts of regulators have helped neutralize analysts' conflicts of interest.[54]

Q. HAVE OTHER REGULATORS OFFERED AN OPINION ON THIS ISSUE?

A. Yes. The FERC addressed the concern about analyst growth rate forecasts *five years ago* in its March 2015 Order on Rehearing, Opinion No. 531-B, where it reaffirmed its rejection of the argument that analyst growth rates should not be used in the DCF analysis because the analysts making those projections allegedly are overly optimistic in their projections.[55] FERC also noted that the appropriate dividend growth rate to include in a DCF analysis is the growth rate expected by the market. In that case, the FERC indicated that while the market may be wrong in its expectations as reflected in the IBES growth projections, the cost of common equity to a regulated enterprise depends upon what the market expects, not upon precisely what is actually going to happen.[56] Since that time, the FERC has re-evaluated the appropriate methodologies to establish the ROE in many opinions; however, the use of earnings growth rates has been consistently applied in all FERC opinions, including the most recent decision in May 2020, Opinion No. 569-A.

Q. DO YOU AGREE WITH MR. PARCELL'S "RETENTION GROWTH" DCF ANALYSIS?

A. No, I do not. The underlying premise of the "retention growth" calculation is that future earnings will increase as the retention ratio (*i.e.*, the portion of earnings not paid out in dividends) increases. There are, however, several reasons why that may not be the case. Management decisions to conserve cash for capital investments, to

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[54] Armen Hovakimian and Ekkachai Saenyasiri, *Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation*, Financial Analysts Journal, Volume 66, Number 4, July/August 2010, at 195. Please note that this appears to be the published version of the working paper cited by Mr. Parcell.

[55] FERC Order on Rehearing, Opinion No. 531-B (March 3, 2015), at para 71.

[56] *Ibid*.

manage the dividend payout for the purpose of minimizing future dividend reductions, or to signal future earnings prospects can and do influence dividend payout (and therefore earnings retention) decisions in the near-term.

Q. IS THERE ACADEMIC RESEARCH THAT SUPPORTS YOUR POSITION?

A. Yes, there is. Almost fourteen years ago, two articles appeared in Financial Analysts Journal, which addressed the theory that high dividend payouts (*i.e.*, low retention ratios) are associated with low future earnings growth.[57] Both of those articles cite a 2003 study by Arnott and Asness,[58] who found that, over the course of 130 years of data, future earnings growth is associated with high, rather than low payout ratios.[59] In essence, the findings of all three studies are that there is a negative, not a positive relationship between earnings growth rates and payout ratios. Therefore, I disagree with Mr. Parcell's use of the retention growth model.

Q. DO YOU HAVE OTHER CONCERNS REGARDING MR. PARCELL'S RETENTION GROWTH RATES?

A. Yes, I do. First, it is important to note that Mr. Parcell ultimately does not rely on the results of his analyses using the retention growth rate. As shown in Exhibit No. ___(DCP-1), Schedule 7, the results of Mr. Parcell's DCF analysis using the retention growth rates are 7.1 percent and 6.7 percent using historical and prospective retention growth rates, respectively. Mr. Parcell establishes a range for his DCF results of 8.70 percent to 9.30 percent.[60] Therefore, it appears that even

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[57] Ping Zhou, William Ruland, *Dividend Payout and Future Earnings Growth*, Financial Analysts Journal, Vol. 62, No. 3, 2006. *See also* Owain ap Gwilym, James Seaton, Karina Suddason, Stephen Thomas, *International Evidence on the Payout Ratio, Earnings, Dividends and Returns*, Financial Analysts Journal, Vol. 62, No. 1, 2006.

[58] Robert Arnott, Clifford Asness, *Surprise: Higher Dividends = Higher Earnings Growth*, Financial Analysts Journal, Vol. 59, No. 1, January/February 2003.

[59] Since the payout ratio is the inverse of the retention ratio, the authors found that future earnings growth is negatively related to the retention ratio.

[60] Direct Testimony of David C. Parcell, at 44.

Mr. Parcell believes the results of these models using retention growth rates are too low to be credible.

In addition, in developing the retention growth rates it is necessary to estimate the earned return on common equity. While Mr. Parcell has not shown the full calculation of the retention growth rates in Exhibit No. (DCP-1), Schedule 7 (p.2), the calculation requires the use of Value Line's projected ROEs for the proxy companies. Thus, Mr. Parcell effectively pre-supposes the return on common equity projected by Value Line for the proxy group companies. As shown in Exhibit No. ___ (DCP-1), the median Value Line earned ROE estimates from 2015-2019 ranged from 9.4 percent to 10.0 percent for the companies in Mr. Parcell's proxy group and from 9.4 percent to 10.8 percent for my proxy group.[61] Yet, the median results of his DCF analyses using historical retention growth rates are 7.1 percent and 7.6 percent—a difference of 230 to 320 basis points. Similarly, his projected retention growth rates produce a median DCF result of 6.7 percent, but the implied ROEs (upon which those growth rates were calculated) actually range from 8.8 percent to 9.5 percent,[62] a difference of 210 to 280 basis points.

In summary, Mr. Parcell's retention growth rate DCF analysis is not reflective of market conditions, and since Mr. Parcell himself has not relied on these estimates to inform his ROE recommendation, it would be reasonable to disregard these analyses.

[61] *See* Exhibit No. ___ (DCP-1), Schedule 10, at 1.
[62] *Id.*, Schedule 7, p. 5.

B. *CAPM Analysis*

Q. PLEASE SUMMARIZE THE RESULTS OF MR. PARCELL'S CAPM ANALYSIS AND HOW HE USES THAT ANALYSES.

A. Mr. Parcell calculates the CAPM using both my proxy group and his own proxy group. The range of results using these groups was 6.40 percent to 6.60 percent.[63] While no regulatory commission has authorized an ROE at this level for a vertically integrated electric utility in the last 35 years, Mr. Parcell suggests that these results should still be considered in setting the ROE for APS.[64] In support of his position, Mr. Parcell ignores the recent market volatility and suggests that risk premiums are lower in this case than in prior years, and suggests that investors' expectations are lower today than in recent years as a result of the actions of the Federal Reserve. Despite specifically stating that the CAPM results should be considered in determining the ROE for APS, Mr. Parcell gave the results of this analysis no weight in developing his recommended ROE range, but suggests that they should be a factor that is considered in the placement of the ROE within the range.[65]

Q. ARE MR. PARCELL'S CAPM RESULTS MEANINGFULLY DIFFERENT IN HIS CURRENT TESTIMONY THAN IN PRIOR CASES?

A. No, they are not. While Mr. Parcell attempts to validate the results of his CAPM by stating that current market conditions have driven the risk premium lower today than in recent cases, based on my review of other cases where he has filed testimony, his CAPM results in this proceeding are consistent with what he estimated over the last five years. Therefore, Mr. Parcell's suggestion that recent conditions have lowered the risk premium is not supported in his own work. In fact, the assumptions used to develop his CAPM analyses have not produced results

[63] Direct Testimony of David C. Parcell, at 34.
[64] *Id.*, at 45.
[65] *Ibid.*

that reflected the range of authorized ROEs in the last five years.[66] Therefore, I do not believe it is reasonable to afford his CAPM results any weight in setting the ROE for APS in this proceeding.

Q. WHAT POINTS DID MR. PARCELL RELY ON IN HIS RANGE FOR HIS FINAL RECOMMENDED ROE?

A. Mr. Parcell's range was set at 9.30 percent to 9.50 percent, which is approximately 290 basis points above the range that is established by his CAPM results. Within that range, Mr. Parcell relies on the midpoint of 9.40 percent as his recommended ROE.[67] It is unclear from this range and point estimate how the results of his CAPM analyses were considered.

Q. DO YOU AGREE WITH THE ASSUMPTIONS USED IN MR. PARCELL'S CAPM ANALYSIS?

A. No, I do not. Furthermore, I do not agree that any commission should be considering the results from a model that are in the range of 6.4 percent to 6.6 percent as credible expectations of the investor required return for a vertically integrated electric utility. As discussed previously, no commission has authorized an ROE at this level for a vertically integrated electric utility over the last 35 years, which is the time-period for which data have been collected. Furthermore, as discussed in Section V, market conditions have been extremely volatile in response to the pandemic and therefore it is unreasonable to suggest that in these volatile conditions that the risk premium for holding equity would be lower than in more stable economic times. Therefore, I disagree with Mr. Parcell's model development and his conclusions justifying the results of this model. However, since these results do not factor into his final recommended range, I have narrowed the scope

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[66] *See* Mr. Parcell's Direct Testimony before the Washington Utilities and Transportation Commission Docket Nos. UE-190334, UE-170485, UE-152253. *See also* the Direct Testimony of Mr. Parcell before the Arizona Public Utilities Commission in Docket E-01933A-15-0322.

[67] Direct Testimony of David C. Parcell, at 44.

of my response to Mr. Parcell and have not addressed each assumption in his CAPM modeling.

Q. WHAT CONCERNS DOES MR. PARCELL EXPRESS REGARDING YOUR CAPM ANALYSES?

A. Mr. Parcell disagrees with my use of projected interest rates and my MRP estimates.

Q. HOW DO YOU RESPOND?

A. The estimation of the cost of equity should be forward-looking since it is the return that investors would receive over the future rate period. Therefore, the inputs and assumptions used in the CAPM analysis should reflect the expectations of the market at that time. I estimated the MRP based on the expected total return on the S&P 500 Index less the 30-year Treasury bond yield. The historical MRP fails to consider the inverse relationship between interest rates and the MRP. As such, it is more appropriate to use a forward-looking MRP that reflects projected total returns for the S&P 500 less the current and projected yield on Treasury securities.

Q. MR. PARCELL STATES THAT IT IS "NOT PROPER TO USE PROJECTED INTEREST RATES AS THE RISK-FREE RATE" AND THAT THE CURRENT YIELD IS THE PROPER RATE BECAUSE IT IS "KNOWN AND MEASURABLE AND REFLECTS INVESTOR'S COLLECTIVE ASSESSMENT OF ALL CAPITAL MARKET CONDITIONS."[68] DO YOU AGREE?

A. No, I do not. First, I disagree that current interest rates reflect investors' collective assessment of all capital market conditions. As I have stated previously in this testimony, current yields on U.S. Treasury securities are being driven by the Federal Reserve's monetary policy, not by typical bond market participants; and today's low interest rates are not reliable indicators of investment risk or the cost

[68] *Id.*, at 35.

of capital in equity markets over the period that the rates in this case will be in effect. It is common practice for analysts to use normalized interest rates (as I have done by using a forecast bond yield), particularly in current market conditions, because forecasted bond yields provide a more reliable indication of investment risk and the cost of capital over the expected rate period.

Q. PLEASE SUMMARIZE MR. PARCELL'S CONCERNS WITH YOUR FORWARD-LOOKING MRP.

A. Mr. Parcell disagrees with the methodology I have used to calculate a forward-looking MRP. Specifically, he disputes my use of a Constant Growth DCF analysis of the S&P 500 companies to determine the total market return because he believes that the EPS growth rates for these companies are over-stated. In addition, he contends that it is not appropriate to subtract current yields on Treasury bonds from the total market return due to the effect of the Federal Reserve's Quantitative Easing on U.S. Treasury yields.[69]

Q. WHAT IS YOUR RESPONSE?

A. First, I disagree with Mr. Parcell that the EPS growth rates for certain companies in the S&P 500 are overstated. I have previously addressed Mr. Parcell's concern with analyst bias. Furthermore, the aggregate growth rate for the S&P 500 Index from Bloomberg (as shown in Attachment AEB-4RB) is very similar to that provided in the Standard and Poor's Earnings and Estimates report (as shown in Attachment AEB-4.5RB). This evidence corroborates the reasonableness of the total market return that I used to calculate a forward-looking MRP. Second, in response to Mr. Parcell's concern with comparing the total market return for the S&P 500 to current Treasury bond yields, I have used both current yields on 30-year Treasury bonds as well as near-term and longer-term projected yields on 30-year Treasury bonds to compute the MRP.

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[69] *Id.*, at 35-36.

Q. ARE THERE OTHER REGULATORY AGENCIES THAT HAVE OFFERED OPINIONS ON A FORWARD-LOOKING CAPM?

A. Yes. In Opinion No. 531-B the FERC specifically addressed the assumptions used in a projected CAPM analysis. The FERC concluded that estimates of the MRP using the same methodology that was used in my Direct Testimony were appropriate. Specifically, the FERC stated:

> …As an initial matter, we reject EMCOS's argument that the NETOs' CAPM analysis is flawed because it used a DCF study to determine the market risk premium. As explained above, using a DCF study is the standard method of calculating the market risk premium in a forward-looking CAPM analysis. We are, therefore, unpersuaded that the use of a DCF study renders the NETOs' CAPM analysis deficient.
>
> We also disagree with Petitioners' argument that the NETOs' CAPM analysis relied on an overly optimistic growth rate input in determining the market risk premium. The growth rate in the NETOs' CAPM analysis is based on IBES data, which the Commission has long relied upon as a reliable source of growth rate data.[70]

In its recent decision in Opinion No. 569-A, the FERC continued to rely on a forward-looking CAPM analysis, weighing the results of that analysis equally with the DCF and the Risk Premium approach.[71]

C. *Comparable Earnings Analysis*

Q. PLEASE EXPLAIN YOUR CONCERNS WITH MR. PARCELL'S COMPARABLE EARNINGS ANALYSIS.

A. Mr. Parcell provides a Comparable Earnings analysis that presents "realized returns" over a period that is too long (as far back as 2002) to be relevant in this proceeding. Many of the proxy companies would not have met my screening criteria during those historical periods, particularly those that have had credit

[70] Opinion No. 531-B, 147 FERC ¶ 61,234 Order on Rehearing (March 3, 2015), at para 110.
[71] Federal Energy Regulatory Commission Opinion No. 569-A, May 21, 2020.

ratings below investment grade. For example, according to Mr. Parcell's Schedule 10, Black Hills Corporation earned an ROE of 0.47 percent in 2008, 5.9 percent in 2010, and 3.6 percent in 2011. According to Black Hill's 10-K, these disappointing returns were not attributable to ongoing utility operations, but rather losses from discontinued or unregulated operations. It makes little sense to incorporate such factors into a forward-looking return estimate, particularly when these events occurred nearly a decade ago. It is not appropriate to bring historical accounting returns into an exercise that is setting forward-looking ROE. Mr. Parcell's review of the historical returns of the proxy group companies is a backward-looking measure with no consideration of or relevance to current market conditions.

D. *Conclusions regarding Mr. Parcell's ROE Recommendation*

Q. WHAT IS YOUR CONCLUSION REGARDING MR. PARCELL'S ROE RECOMMENDATION OF 9.40 PERCENT?

A. While I present several results in my testimony, I consider the effect of market conditions on the models in my determination of the appropriate ROE. In contrast, while Mr. Parcell criticizes the assumptions used in my analyses in support of his own methodologies, he discards many of his own results. Specifically, Mr. Parcell offers extensive criticism of the assumptions used in my CAPM, offering instead his view on the appropriate specification of this model, then discards the results of that model.

With respect to the DCF model, Mr. Parcell spends pages criticizing my exclusive use of EPS growth rates, yet the only DCF result from the myriad of growth rates he uses in his DCF model is the one derived from EPS growth rates.

E. *Fair Value Increment Cost Rate*

Q. PLEASE SUMMARIZE MR. PARCELL'S PROPOSED FVROR AND FVI COST RATE.

A. Mr. Parcell recommends a FVROR of 5.11 percent for APS, calculated from his recommended ROE of 9.40 percent and a FVI cost rate of 0.30 percent.

Mr. Parcell recommends a FVI cost rate of between 0.00 percent and 0.60 percent.[72] In support of his position that the return on the FVI should be zero, Mr. Parcell states that "[s]ince the increment between the FVRB and OCRB is not financed with investor-supplied funds, it is logical and appropriate, from a financial standpoint, to assume that this increment has no financing costs."[73]

Despite that recommendation, Mr. Parcell nonetheless provides a calculation of the return on the FVI. In that calculation, Mr. Parcell estimates the real risk-free rate as the nominal risk-free rate of 2.6 percent (which he states was the yield on various maturities of Treasury securities in 2019) less a projection of CPI as a measure of inflation (which he states is 2.0 percent for 2021), resulting in a real risk free rate of 0.6 percent.

Mr. Parcell's calculation of the return on the FVI applies 50 percent of the real risk-free rate, or 0.30 percent, to the FVI.[74] The FVROR resulting from this final method is 5.11 percent.[75]

Q. DO YOU AGREE WITH MR. PARCELL'S RECOMMENDATION?

A. While I generally agree that the return on the FVI should be based on the real risk-free rate, I do not agree with the approach Mr. Parcell has used to calculate that return. Mr. Parcell relies on projected Treasury bond yields for a very short term,

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[72] Direct Testimony of David C. Parcell, at 53.
[73] *Id.*, at 49.
[74] *Id.*, at 48-49.
[75] *Id.*, at 53.

ending in 2019. As shown Attachment AEB-8RB, the average projected yield on the 30-year Treasury bond is 3.40 percent, which is significantly higher than the historical yield relied upon by Mr. Parcell. Calculating the real risk-free rate from that figure using the yields on the Treasury Inflation Protected Securities (TIPS) results in a real risk-free rate of 1.83 percent, which is 123 basis points higher than the real risk-free rate estimated by Mr. Parcell.

Q. WHAT IS THE EFFECT ON THE FVROR OF UPDATING MR. PARCELL'S FVI COST RATE?

A. While I disagree with Mr. Parcell's recommended ROE of 9.40 percent, for the purposes of illustration, the FVROR resulting from Mr. Parcell's ROE, combined with the Company's requested FVI cost rate of 0.80 percent, would be 5.40 percent.

As shown in Attachment AEB-9RB, the FVROR resulting from the Company's proposed ROE of 10.00 percent, combined with the Company's requested FVI cost rate of 0.80 percent, is 5.51 percent.

VII. RESPONSE TO RUCO WITNESS CASSIDY

Q. PLEASE SUMMARIZE MR. CASSIDY'S ANALYSES AND RECOMMENDATIONS.

A. Mr. Cassidy develops a range of ROE estimates from 7.64 percent to 10.00 percent and recommends a base ROE for APS of 8.94 percent by placing 40 percent weight on the results of both his DCF and Comparable Earnings analysis and 20 percent weight on the results of his CAPM analysis.[76] Mr. Cassidy does not provide any rationale or support for the weights he has assigned to each model, although he notes that the Commission has traditionally given the most weight to the DCF and CAPM methodologies.[77] The low results of Mr. Cassidy's CAPM analysis (midpoint of 7.68 percent) form the lower boundary of his range of results, while

[76] Direct Testimony of John A. Cassidy, at 6.
[77] *Id.*, at 4.

the high results of his Comparable Earnings analysis (midpoint of 9.75 percent) form the upper boundary of his range. His Constant Growth DCF model produces mean results of 8.75 percent. Mr. Cassidy further reduces the recommended ROE for APS by 20 basis points to 8.74 percent, based on the recommendation of RUCO Witness Mr. Jordy Fuentes.

Mr. Cassidy supports the Company's proposed capital structure of 54.67 percent common equity and 45.33 percent long-term debt. Further, RUCO recommends a FVROR for APS of 4.69 percent, based on a return on the FVI of 0.0 percent.[78]

Q. DOES MR. CASSIDY'S ROE RECOMMENDATION FOR APS MEET THE FAIR RETURN STANDARD OF *HOPE* AND *BLUEFIELD*?

A. No, it does not. Mr. Cassidy's ROE recommendation of 8.94 percent (less 20 basis points for a management performance penalty) is 106 basis points below APS's currently authorized ROE of 10.0 percent and well below authorized returns available to investors from other comparable-risk investments. As discussed in my Direct Testimony, the *Hope* and *Bluefield* decisions of the U.S. Supreme Court established the legal precedent for determining whether an authorized ROE is just and reasonable.[79] Those decisions establish three legal standards that must be met in order for a return to be considered just and reasonable: 1) the financial integrity standard; 2) the capital attraction standard; and 3) the comparable return standard. None of these standards ranks higher in importance, and all three standards must be satisfied in order for the return to be considered just and reasonable. On that basis, Mr. Cassidy's ROE recommendation for APS does not meet the comparable return standard of *Hope* and *Bluefield*, and likely does not meet the financial integrity and capital attraction standards.

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[78] *Id.*, at 72.

[79] Direct Testimony of Ann E. Bulkley, at 9-10.

Q. DO YOU HAVE OTHER CONCERNS WITH MR. CASSIDY'S ROE ANALYSIS AND RECOMMENDATION?

A. Yes. While Mr. Cassidy recognizes the extraordinary economic uncertainty that has been introduced by the COVID-19 pandemic,[80] he concentrates on the economic conditions (high unemployment, lower economic growth, lower consumer sentiment) and the policy response from the Federal Reserve and the U.S. Congress.[81] Mr. Cassidy contends that the Federal Reserve is expected to maintain the federal funds rate near zero for several years and that inflation is expected to remain low for the next 10 years.[82] He also concludes that equity returns will be lower than the historical levels through 2035, citing a McKinsey report as support for his position.[83]

I disagree with Mr. Cassidy's primary focus on the low level of interest rates on government and corporate bonds because it ignores other important indicators such as volatility in equity markets and substantial increases in utility Beta coefficients, both of which suggest that the cost of equity has increased for regulated utilities such as APS. Mr. Cassidy's ROE recommendation does not reflect the elevated level of risk for equity investors under current and prospective market conditions that APS will face during the period in which rates set in this proceeding will be in effect. Finally, Mr. Cassidy has failed to take into consideration additional business and regulatory risks that differentiate APS from the proxy group companies.

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[80] Direct Testimony of John A. Cassidy, at 10-11.
[81] *Id.*, at 13-17.
[82] *Id.*, at 25.
[83] *Id.*, at 33.

Q. MR. CASSIDY HAS EXCLUDED TWO COMPANIES FROM HIS PROXY GROUP THAT WERE INCLUDED IN THE PROXY GROUP IN YOUR DIRECT TESTIMONY. WHAT IS YOUR RESPONSE?

A. Mr. Cassidy contends that First Energy Corp. and PPL Corporation should not be included in the proxy group for APS. In updating my ROE analysis for rebuttal, I note that both First Energy and PPL have projected EPS growth rates from only one source. Therefore, both companies now fail one of my screening criteria for inclusion in the proxy group. I have excluded both First Energy and PPL in my updated ROE analysis for APS.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF DISAGREEMENT WITH MR. CASSIDY'S ROE ANALYSES?

A. I disagree with the following aspects of Mr. Cassidy's analyses: (1) his reliance on the Constant Growth DCF model and the relevance of results produced by that model under current market conditions; (2) the appropriate growth rate to be used in the Constant Growth DCF model; (3) his application of the CAPM and the reasonableness of his CAPM results; (4) his failure to take into consideration the higher business and regulatory risks to which APS is exposed relative to the proxy group companies; and (5) his FVROR recommendation and the method used to derive that recommendation.

A. *Reliance on Constant Growth DCF Model and Relevance of Results*

Q. MR. CASSIDY OBSERVES THAT THE DCF MODEL IS ONE OF THE OLDEST AND MOST COMMONLY USED MARKET BASED MODELS TO ESTIMATE THE COST OF EQUITY FOR PUBLIC UTILITIES, AND HE ASSERTS THAT THE DCF MODEL IS THE ONLY MODEL THAT INTRINSICALLY CONSIDERS THE PRICE INVESTORS PAY FOR A GIVEN UNIT OF RETURN.[84] WHAT IS YOUR RESPONSE?

A. I recognize that the DCF model has been commonly used by many utility regulators to establish the authorized ROE for regulated utilities. However, as discussed in my Direct Testimony, the Constant Growth DCF model is based on certain underlying assumptions, one of which is that the price/earnings ratio will remain constant in perpetuity.[85] To the extent that assumption is not satisfied, the results of the DCF model should be treated with caution. As explained in Section V of my Rebuttal Testimony, and as Mr. Walters recognizes in his testimony, the proxy group companies are trading at valuations that are high despite the market correction, and many analysts do not view those valuations as sustainable. Therefore, as explained in my Direct Testimony, several utility regulators including FERC have moved away from sole reliance on the DCF model and are now considering the results of alternative risk premium based models such as the forward-looking CAPM analysis and the Bond Yield Plus Risk premium analysis to establish the cost of equity for regulated utilities.[86] Furthermore, since the filing of my Direct Testimony, in May 2020, FERC issued Opinion No. 569-A in which they established that the ROE for the Midwest Independent System Operator transmission companies would be set based on the average results of the DCF, CAPM and Risk Premium approaches, taking into consideration the relative risk

[84] Direct Testimony of John A. Cassidy, at 43.
[85] Direct Testimony of Ann E. Bulkley, at 40.
[86] *Id.*, at 35-38.

of the subject company to move within the zone of reasonableness established by the averages of these three methodologies.

Q. HOW DO THE RESULTS OF MR. CASSIDY'S CONSTANT GROWTH DCF MODEL COMPARE TO COMPARABLE RETURNS AUTHORIZED FOR INTEGRATED ELECTRIC UTILITIES IN OTHER JURISDICTIONS?

A. Mr. Cassidy's DCF model results range from 6.98 percent to 9.58 percent.[87] He narrows that range to between 8.00 percent (the approximate mean result using an average of all growth rates considered for his proxy group) and 9.50 percent (which is slightly below the median high for his proxy group of 9.58 percent based on EPS growth rates) and selects the midpoint of 8.75 percent as his DCF derived cost of equity for the proxy group.[88] Mr. Cassidy assigns 40.0 percent weight to his DCF results in estimating a just and reasonable cost of equity for APS. Mr. Cassidy's DCF return estimate of 8.75 percent is approximately 90 basis points below the average equity returns that have been authorized for integrated electric utilities nationwide since January 2018. This differential is partly attributable to the low dividend yields for the proxy group companies, which have been reduced to near historically low levels as investors search for alternatives to the low yields available on U.S. Treasury securities. The results of Mr. Cassidy's DCF model do not provide investors the opportunity to earn a return comparable to investments in other enterprises with similar risk. As such, Mr. Cassidy's DCF model results do not meet the standards of *Hope* and *Bluefield* for a fair return.

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[87] Direct Testimony of John A. Cassidy, at 46.
[88] *Ibid.*

B. *Appropriate Growth Rate in Constant Growth DCF Model*

Q. WHAT GROWTH RATES DOES MR. CASSIDY CONSIDER IN HIS CONSTANT GROWTH DCF ANALYSIS?

A. Mr. Cassidy considers five sources of growth rates in his Constant Growth DCF analysis, including five-year historical and projected retention growth rates from Value Line, five-year historical and projected compound growth rates in EPS, DPS and BVPS from Value Line, and five-year projections of EPS growth rates from analysts as reported by Yahoo! Finance.[89]

Q. WHY DO YOU DISAGREE WITH THE GROWTH RATES THAT MR. CASSIDY RELIES ON IN HIS DCF ANALYSIS?

A. I disagree with the use of historical growth rates, dividend and book value per share growth rates, and retention growth rates. I have addressed my concerns with the use of retention growth rates in my response to Mr. Parcell. Mr. Cassidy also expresses concern with the potential for analyst bias in earnings per share growth rates. I have also addressed that issue in my response to Mr. Parcell.

Q. DO YOU AGREE WITH MR. CASSIDY THAT HISTORICAL MEASURES OF GROWTH ARE RELEVANT TO A FORWARD-LOOKING EVALUATION OF THE COST OF EQUITY?

A. While I agree that historical measures of growth are relevant, these historical growth rates are likely already incorporated into investors' forward-looking growth rates. Therefore, specific reliance on historical growth rates is likely to overweight history in the analysis. The Constant Growth DCF model is a forward-looking model that evaluates investors' required returns based on expected future cash flows. As such, the appropriate measure of growth in the DCF analysis is investors' expectations.

[89] Direct Testimony of John A. Cassidy, at 45.

Q. WHAT IS YOUR CONCERN WITH MR. CASSIDY'S USE OF DIVIDEND AND BOOK VALUE GROWTH RATES IN THE DCF MODEL?

A. As discussed in my response to Mr. Parcell, earnings are the fundamental driver of a company's ability to pay dividends; therefore, earnings growth is the appropriate measure of a company's long-term growth. As noted by Brigham and Houston:

> Growth in dividends occurs primarily as a result of growth in earnings per share (EPS). Earnings growth, in turn, results from a number of factors, including (1) inflation, (2) the amount of earnings the company retains and invests, and (3) the rate of return the company earns on its equity (ROE).[90]

In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain certain earnings rather than include those earnings in a dividend issuance. Therefore, dividend growth rates are less likely than earnings growth rates to reflect investor perceptions of a company's growth prospects.

Furthermore, investment analysts report predominant reliance on EPS growth projections. In a survey completed by 297 members of the Association for Investment Management and Research, the majority of respondents ranked earnings as the most important variable in valuing a security (more important than cash flow, dividends, or book value).[91]

Academic research also supports the use of EPS growth estimates. A 2002 study in the *Journal of Accounting Research*, examined "the valuation performance of a comprehensive list of value drivers" and found that "forward earnings explain stock prices remarkably well" and were generally superior to other value drivers

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[90] Eugene F. Brigham and Joel F. Houston, Fundamentals of Financial Management, at 317 (Concise Fourth Edition, Thomson South-Western, 2004).

[91] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory," Financial Analysts Journal (July/August 1999).

analyzed.[92] A 2012 study from the journal *Contemporary Accounting Research* found that the sell-side analysts with the most accurate stock price targets were those whom the researchers found to have more accurate earnings forecasts.[93]

Q. WHAT WOULD BE THE RESULTS OF MR. CASSIDY'S CONSTANT GROWTH DCF MODEL IF HE HAD RELIED ONLY ON PROJECTED EPS GROWTH RATES?

A. As shown in Schedule JAC-3, page 4 of 4, if Mr. Cassidy had relied on the consensus projected EPS growth rates from Yahoo! Finance for his proxy group, the median results of his Constant Growth DCF model would be 9.58 percent and the mean results would be 9.33 percent. The use of other sources of growth rates (i.e., historical growth rates, retention growth rates, and dividend and book value growth rates) causes the results of Mr. Cassidy's DCF analysis to produce a mean ROE estimate of 7.99 percent. For example, his DCF analysis using historical and projected retention growth rates produces median results of 7.35 percent and 7.06 percent, respectively. Similarly, Mr. Cassidy's DCF analysis using projected EPS, DPS and BVPS growth rates produces median results of 7.89 percent, while his DCF model using historical EPS, DPS and BVPS provides median results of 8.48 percent. I have explained why EPS growth rates are the best indicator of stock prices and why it is not reasonable to use historical growth, retention growth, and dividend or book value growth in the DCF analysis. Further, to the extent that high valuations are not sustainable, the results of the Constant Growth DCF model even with projected EPS growth rates under-estimate investors' return requirements on a going-forward basis. For that reason, it is necessary and appropriate to also

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[92] Liu, Jing, et al., "Equity Valuation Using Multiples," Journal of Accounting Research, Vol. 40 No. 1, March 2002.

[93] Gleason, C.A., et al., "Valuation Model Use and the Price Target Performance of Sell-Side Equity Analysts," *Contemporary Accounting Research*.

consider the results of other models that can be adjusted to better reflect prospective market conditions over the near to intermediate term.

Q. WHAT IS YOUR CONCLUSION REGARDING THE CONSTANT GROWTH DCF MODEL DEVELOPED BY MR. CASSIDY?

A. The results of Mr. Cassidy's Constant Growth DCF demonstrate the flaws with relying on historical growth rates in determining the ROE. As shown in Schedule JAC-3, the results of these analyses range from 6.98 percent to 8.48 percent, which are well below the authorized ROEs in any regulatory jurisdiction in any recent time-period. Furthermore, the results of Mr. Cassidy's Constant Growth DCF model should be largely discounted, or at a minimum not considered in isolation because the current market conditions have affected the dividend yields in the DCF models, thereby understating the cost of equity. As discussed previously in my Direct Testimony and in my Rebuttal Testimony, this ongoing concern with the DCF model results has caused other regulatory commissions to consider the results of multiple models in establishing the appropriate ROE.

C. *Application of Capital Asset Pricing Model*

Q. PLEASE SUMMARIZE MR. CASSIDY'S CAPM ANALYSIS AND RESULTS.

A. Mr. Cassidy's CAPM analysis relies on a historical MRP of 7.40 percent, the three-month average yield on 20-year Treasury bonds of 1.16 percent as the risk-free rate, and the average Value Line Beta for his proxy group of 0.89. In particular, Mr. Cassidy notes the substantial increase in utility Beta coefficients that has coincided with increased market volatility during the COVID-19 pandemic.[94] As shown in Schedule JAC-4, that analysis produces an average ROE estimate for APS of 7.73 percent and a median result of 7.64 percent. Mr. Cassidy assigns 20.0

[94] Beta is the measure of systematic risk that cannot be offset by holding a diversified portfolio.

percent weight to his CAPM results in estimating a just and reasonable cost of equity for APS.[95]

Q. PLEASE COMMENT ON THE REASONABLENESS OF MR. CASSIDY'S CAPM RESULTS.

A. Mr. Cassidy's CAPM results of 7.68 percent are entirely inconsistent with the returns required by equity investors for companies with commensurate risk and are 232 basis points below APS's currently authorized ROE of 10.00 percent. Furthermore, consistent with the results of his DCF analyses using historical growth rates, Mr. Cassidy's CAPM results have never been observed as an authorized ROE for any integrated electric utility in at least the past 35 years.

Q. WHAT ARE THE SPECIFIC ASPECTS OF MR. CASSIDY'S CAPM ANALYSIS WITH WHICH YOU DISAGREE?

A. I disagree with Mr. Cassidy's sole reliance on the current average yield on the 20-year Treasury bond as the risk-free rate and with his use of a historical MRP when, as Mr. Cassidy notes, current market conditions have demonstrated significant volatility and during a time in which the current risk-free rate is substantially lower than the average yield on government bonds over the period from 1978-2019 that Mr. Cassidy uses to calculate his MRP.

Q. DO YOU AGREE WITH MR. CASSIDY THAT THE CAPM IS A FORWARD-LOOKING MODEL?

A. I agree that the CAPM is a forward-looking model when the risk-free rate and the MRP are based on projected data. However, the inputs Mr. Cassidy uses in the model (i.e., risk free rate, beta, and MRP) are all based on either current or historical market data, not forward-looking data. The CAPM cannot be considered forward-looking when it is based entirely on historical assumptions.

[95] Direct Testimony of John A. Cassidy, Schedule JAC-4.

Q. PLEASE DISCUSS YOUR CONCERN WITH THE RISK-FREE RATE MR. CASSIDY USES IN HIS CAPM ANALYSIS.

A. It is not appropriate to rely exclusively on current average yields on U.S. Treasury bonds as the risk-free rate in the CAPM analysis because government bond yields are being suppressed by the extraordinary monetary policy accommodation that the Federal Reserve has provided in response to the COVID-19 pandemic. Mr. Cassidy's risk-free rate of 1.16 percent (which is based on 20-year Treasury bond yields) is 184 basis points lower than the projected yield on 30-year Treasury bonds over the period from 2022-2026. Investors are expecting a substantial increase in government bond yields once interest rate policy normalizes again. Therefore, the use of current government bond yields does not reflect the risk-free rate that investors are expected during the period when the rates set in this proceeding for APS will be in effect.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH MR. CASSIDY'S RISK-FREE RATE?

A. Yes. In addition to my concern with Mr. Cassidy's use of current yields on government bonds rather than projected yields, I also disagree with his use of the 20-year Treasury bond as the risk-free rate. I prefer the use of the 30-year Treasury bond yield because it more closely matches the holding period for common equity. Further, utility assets tend to have average useful lives that exceed 20 years. A fundamental premise of prudent financial management is that the term of the instrument used to finance an asset should match the useful life of the asset. Based on 2019 financial data for APS, the average useful life of the Company's utility assets is approximately 24.5 years.[96] In this instance, Mr. Cassidy's use of 20-year government bonds is not consistent with the average useful life of APS utility assets.

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[96] Calculation: Average net utility plant of $12,784,290,000 / 2019 depreciation expense of $522 million = 24.5 years. Pinnacle West Capital Corporation 2019 Form 10-K, at 92 and 99.

Q. PLEASE EXPLAIN YOUR CONCERN WITH THE USE OF A HISTORICAL MRP IN THE CAPM.

A. My concern with the use of a historical MRP is that it fails to reflect the inverse relationship between interest rates and the MRP. That is, as interest rates decrease, the MRP increases. Based on historical data from Duff & Phelps, Mr. Cassidy calculates the MRP from 1978-2019 as 7.40 percent.[97] The historical average return on 20-year Treasury bonds used by Mr. Cassidy to calculate the historical MRP over the same period was approximately 6.39 percent, while the current 30-day average risk-free rate on 30-year Treasury bonds is 1.42 percent. Because current interest rates on long-term government bonds are well below the historical average of 6.39 percent, the inverse relationship between interest rates and the MRP implies that the MRP should be well above the long-term historical average of 7.40 percent.

Q. IS THERE EVIDENCE THAT THE USE OF A HISTORICAL MRP MAY PRODUCE COUNTER-INTUITIVE RESULTS?

A. Yes, there is. Relying on a historical MRP may produce results that are not consistent with investor sentiment and current conditions in capital markets. For example, Morningstar observes:

> It is important to note that the expected equity risk premium, as it is used in discount rates and the cost of capital analysis, is a forward-looking concept. That is, the equity risk premium that is used in the discount rate should be reflective of what investors think the risk premium will be going forward.[98]

Figure 10 illustrates the problem with relying on the historical MRP. Specifically, the Figure shows that from 2007-2009 the historical MRP decreased from 7.10 percent to 6.70 percent even as market volatility (the primary statistical measure of risk) significantly increased.

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[97] Direct Testimony of John A. Cassidy, at 52.

[98] Morningstar Inc., 2010 Ibbotson Stocks, Bonds, Bills, and Inflation, Valuation Yearbook, at 55.

Figure 10: Historical Market Risk Premium and Market Volatility

	Market Volatility	Historical Market Risk Premium[99]
2009	31.48	6.70%
2008	32.69	6.50%
2007	17.54	7.10%

The assumption that investors would expect or require a lower risk premium during periods of increased volatility is counter-intuitive and leads to unreliable analytical results. This is particularly relevant under current market conditions, when, as discussed in Section V of my rebuttal testimony, volatility in both equity markets has increased well above the long-term historical average. Mr. Cassidy recognizes that volatility has increased, noting that Beta coefficients (which are a measure of relative volatility) for utilities in the proxy group have increased substantially since the time when my Direct Testimony was filed.[100] Assuming a lower MRP during periods when volatility in equity markets is elevated and government bond yields are artificially suppressed by Federal Reserve monetary policy is at odds with that premise. The forward-looking MRP estimates used in my CAPM analysis specifically address that concern.

Q. WHAT IS YOUR CONCLUSION REGARDING MR. CASSIDY'S CAPM ANALYSIS?

A. Mr. Cassidy's inputs to the CAPM analysis are based on historical data rather than forward-looking investor expectations. Under the current interest rate environment, the use of historical data for the risk-free rate and MRP does not produce reliable CAPM results. Consequently, Mr. Cassidy's CAPM analysis provides no

[99] Morningstar Inc., 2008 Ibbotson Stocks, Bonds, Bills, and Inflation, Valuation Yearbook, at 28. Morningstar Inc., 2009 Ibbotson Stocks, Bonds, Bills, and Inflation, Valuation Yearbook, at 23. Morningstar Inc., 2010 Ibbotson Stocks, Bonds, Bills, and Inflation, Valuation Yearbook, at 23. Historical Market Risk Premium equals total return on large company stocks less income only return on long-term government securities.

[100] Direct Testimony of John A. Cassidy, at 51-52.

meaningful insight into the cost of equity and should be given no weight in the determination of the authorized ROE for APS.

D. *Comparable Earnings Analysis*

Q. PLEASE EXPLAIN YOUR CONCERNS WITH MR. CASSIDY'S COMPARABLE EARNINGS ANALYSIS.

A. Mr. Cassidy provides a Comparable Earnings analysis that is very similar to that prepared by Mr. Parcell. Mr. Cassidy's Comparable Earnings analysis is based on historical returns on equity over five and ten-year periods, as well as projected returns on equity over near term and five-year periods.[101] Mr. Cassidy's Comparable Earnings analysis produces return estimates ranging from 9.50 percent to 10.0 percent, and he ultimately selects the midpoint of 9.75 percent as his Comparable Earnings estimate. My concerns with Mr. Cassidy's Comparable Earnings analysis are addressed in my response to Mr. Parcell where I address the problem with using historical returns on equity instead of projected ROEs.

Q. DO YOU HAVE ANY OTHER COMMENTS ON MR. CASSIDY'S COMPARABLE EARNINGS ANALYSIS?

A. Yes. It is important to note that while he criticizes my use of the Expected Earnings methodology, citing to recent FERC precedent, Mr. Cassidy's Comparable Earnings analysis uses the same projected earned return data reported by Value Line that forms the basis of my Expected Earnings analysis. In Opinion No. 569 (affirmed in Opinion No. 569-A), the FERC's stated reason for rejecting the Expected Earnings approach was because the Value Line data on which the analysis was developed was based on the earned return on book value and therefore is an accounting-based methodology.[102] In Opinion No. 569-A, FERC also left open the opportunity for this methodology to be reconsidered in the future. It is

[101] Direct Testimony of John A. Cassidy, Schedule JAC-5.

[102] Federal Energy Regulatory Commission, Opinion No. 569, November 21, 2019, at 209.

unclear to me how Mr. Cassidy can criticize my use of this data and the Expected Earnings analysis citing to FERC when his historical Comparable Earnings approach is based on historical earned returns on book value, the primary basis of FERC's concerns.

E. *Business and Regulatory Risk*

Q. HAS MR. CASSIDY TAKEN INTO CONSIDERATION THE RISK OF APS RELATIVE TO THE PROXY GROUP COMPANIES IN ESTABLISHING HIS RECOMMENDED ROE?

A. No, he has not. Mr. Cassidy does not address the relative business and regulatory risk of APS as compared with the proxy group companies. His ROE recommendation of 8.94 percent, prior to RUCO's proposed 20 basis point ROE adjustment, is derived by assigning 40.0 percent weight each to the midpoint results of his Constant Growth DCF model and his Comparable Earnings analysis and 20.0 percent weight to the midpoint results of his CAPM analysis.

As explained in my Direct Testimony, APS has greater business and regulatory risk than the proxy group companies, which supports an authorized ROE above the results for the proxy group companies.

F. *Fair Value Increment Cost Rate*

Q. PLEASE SUMMARIZE RUCO'S RECOMMENDATION WITH RESPECT TO THE FVROR FOR APS.

A. RUCO recommends a FVROR of 4.69 percent for APS, calculated from Mr. Cassidy's recommended ROE of 8.74 percent and his recommended FVI cost rate of 0.00 percent. While Mr. Cassidy provides a calculation for a FVI cost rate of 0.28 percent, he proposes that no cost rate be applied to the FVI.[103] Mr. Cassidy derives his FVI cost rate of 0.28 percent by subtracting a projected inflation rate of

[103] Direct Testimony of John A. Cassidy, Schedule JAC-1.

1.30 percent for the fourth quarter of 2021 from the projected yield on 30-year Treasury bonds of 1.58 percent for the second quarter of 2021.

Q. DO YOU AGREE WITH THE METHODOLOGY MR. CASSIDY HAS USED TO DERIVE A FVROR FOR APS?

A. No, I do not. In recent rate cases for APS, TEP, and UNS Electric, the Commission has applied a positive rate of return to the FVI of rate base in establishing the FVROR. In the TEP case, Mr. Cassidy proposed a zero-cost increment for the FVI under the assumption that investors have not provided additional capital to finance the FVI above the Original Cost Rate Base (OCRB). Therefore, while Mr. Cassidy has proposed his view on this issue in prior cases, the Commission has determined that it is appropriate to authorize a return on the FVI to reflect an investor required-return on the full equity position in the company's investment. Further, a zero percent return entirely negates the intent of the Arizona statute, which is to allow the utility to earn a return on the FVI of rate base.

Q. DO YOU AGREE WITH MR. CASSIDY'S METHODOLOGY FOR ESTIMATING THE FVROR?

A. While I agree with Mr. Cassidy's overall methodology for estimating the FVROR (i.e., by subtracting projected inflation from the projected nominal risk-free rate), I do not agree with his use of the near-term projected yield on Treasury bonds as the nominal risk-free rate. As discussed in my response to Mr. Parcell, and as shown in Attachment AEB-8RB, using multiple approaches, estimates of the real risk-free rate range from 0.93 percent to 1.83 percent. In my view, the nominal risk-free rate should consider the long-term projected yield on U.S. Treasury bonds (which is currently 3.00 percent for the period from 2022-2026) and Duff & Phelps' normalized risk-free rate of 2.50 percent. The rationale for using longer-term projections is that utility investments are long-term in nature with many assets having service lives that exceed 30 years. In addition, the rates set for APS in this proceeding will be in effect beyond the fourth quarter of 2021, so it is reasonable to base returns on long-term projections rather than short-term forecasts. Substituting either long-term projection of 3.00 percent or 2.50 percent as the nominal risk-free rate and using Mr. Cassidy's projected inflation rate of 1.30 percent would produce a real risk-free rate between 1.70 percent and 2.20 percent. These real risk-free rates are well above Mr. Cassidy's estimate of the real risk-free rate of 0.28 percent.

Q. WHAT IS YOUR CONCLUSION WITH RESPECT TO THE APPROPRIATE FVROR FOR APS?

A. Since the cost of equity is a forward-looking concept, it is reasonable to estimate an appropriate return on the FVI based on the difference between the projected risk-free rate and inflation. The methodology that I have employed is consistent with the approach proposed by RUCO, although I have used long-term estimates of the risk-free rate and inflation, whereas Mr. Cassidy has used short-term estimates. I conclude that the use of the real risk-free rate of return of 1.28 percent is a conservative estimate of the appropriate return on the FVI. However, APS is requesting a FVI cost rate of 0.80 percent, which is conservative compared to the real risk-free rate of 1.28 percent.

VIII. <u>RESPONSE TO FEA WITNESS WALTERS</u>

Q. PLEASE SUMMARIZE MR. WALTERS' TESTIMONY AND RECOMMENDATIONS.

A. As summarized in Figure 11, Mr. Walters presents ROE estimation model results ranging from 8.31 percent to 12.16 percent. He uses three analytical approaches to produce his results: (1) a DCF model (a constant growth version using analyst growth rates, a constant growth version using "sustainable" growth rates, and a multi-stage version), (2) a Bond Yield Plus Risk Premium analysis, and (3) a CAPM analysis. Mr. Walters recommends a 9.30 percent ROE for APS.

Figure 11: Summary of Witness Walters' ROE estimation results

	Range of Walters' analytical results	Walters' judgment of summary result	Walters' recommended ROE
DCF model	8.64 – 9.50%	9.1%	9.30% (mean of 9.1, 9.0, and 9.6)
Bond Yield Plus Risk Premium analysis	8.50 – 9.20%	9.0%	
CAPM	8.31 – 12.16%	9.6%	

In addition, while Mr. Walters does not support use of a FVI cost rate, he offers a recommendation that it be set at 0.65 percent.

Finally, regarding the Company's capital structure, Mr. Walters recommends approving the Company's proposed common equity ratio of 54.67 percent.

Q. WHAT ARE THE MAJOR AREAS OF DISAGREEMENT BETWEEN YOU AND MR. WALTERS?

A. Mr. Walters and I disagree meaningfully regarding the following six topics: (1) our characterizations of the current economic context for determining APS's authorized ROE, (2) which analytical approaches to use and how much weight to put on their results, (3) Mr. Walters' assumptions for "sustainable" growth rates in his DCF models, (4) the fundamental validity of Mr. Walters' methodology for his Bond Yield Plus Risk Premium analysis, (5) Mr. Walters' assumptions for the risk-free interest rate, proxy company Beta, and MRP in the CAPM, and (6) our assessments of APS's business risk.

A. *Current economic context for determining APS's authorized ROE*

Q. DO YOU AGREE WITH MR. WALTERS' IDENTIFICATION OF A DOWNWARD TREND IN AUTHORIZED ROES FOR ELECTRIC UTILITIES?

A. No, I do not. Mr. Walters uses historical data on authorized ROEs for electric and natural gas utilities to argue that there has been a declining trend over a period of years.[104] However, Mr. Walters' review of the historical data relies simply on annual averages, rather than considering the underlying data points. Such an approach to data analysis and data visualization can have the effect of masking important detail and exaggerating the sense of a trend.

As demonstrated in Figure 2, historical data on authorized ROEs are better presented as a scatterplot of the individual underlying data points—rather than as a single line graph of the annual average. As is evident upon review of the data in Figure 2, Mr. Walters' recommended ROE of 9.30 percent is well below the vast majority of authorized ROEs for vertically integrated electric utilities since January 2018.

While it is important to consider all of the underlying data points, if one still wishes to resolve the data for each year into a single value (as Mr. Walters does), it would be important to first consider the difference in average authorized ROEs for vertically integrated utilities (such as APS) versus distribution companies. As shown in Figure 9 in my response to Mr. Parcell, the average authorized ROEs for vertically integrated electric utilities have been higher than for distribution utilities-and thus higher than the simple annual average of all electric utilities.

Q. DO YOU AGREE WITH MR. WALTERS' CHARACTERIZATION OF THE TREND IN ELECTRIC UTILITY CREDIT RATINGS?

A. No, I do not. Mr. Walters asserts that electric utility credit ratings have increased over the past decade.[105] However, in making that statement, Mr. Walters ignores the more recent trend in credit ratings. (In addition, his four months of data for 2020 are labeled "year end."[106]) In addition, it is important to understand that financial health problems can exist prior to being reflected in credit rating changes.

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[104] Direct Testimony of Christopher C. Walters, Figure 1 at 4, and Table 1 at 5.
[105] *Id.*, at 7.
[106] *Id.*, Table 3, at 7.

For example, low debt coverage ratios can be a leading indicator that credit ratings may not recover quickly and/or could suffer further downgrades. A recent article by S&P noted (without any accompanying ratings downgrade announcement) that:

> The average interest-coverage ratio at U.S. companies classified as investment-grade by S&P Global Ratings declined to 5.48 in the second quarter from 5.65 in the first quarter and 6.32 at the end of 2019. [107]

Furthermore, S&P noted that the average interest coverage ratio for utilities was very low, at 2.49 for investment grade utilities.[108]

Despite Mr. Walters' positive characterization of utility credit ratings, the quotes from S&P that he offers indicate that the rating agency has identified concerns for the industry. For example, he quotes S&P as stating that utilities are operating "closer to the downgrade threshold" and facing "many challenges."[109]

Q. PLEASE SUMMARIZE AND RESPOND TO MR. WALTERS' PERSPECTIVE ON THE RELATIONSHIP BETWEEN AUTHORIZED ROES AND UTILITY FINANCIAL HEALTH.

A. Mr. Walters incorrectly implies that utility credit ratings are not adversely affected by lower authorized ROEs.[110] However, there are recent examples that the authorization of ROEs that are below investor expectation can and do adversely affect utility credit ratings.

For example, Moody's recently downgraded ALLETE, Inc. from A3 to Baa1 for reasons that included the less than favorable outcome in Minnesota Power's last rate case in Minnesota. Moody's viewed Minnesota Power's recent rate case decision as credit negative for reasons that included: (1) the below-average

[107] S&P Global Market Intelligence. "US companies less able to service debt even with borrowing costs at record low," October 6, 2020.
[108] *Ibid.*
[109] Direct Testimony of Christopher C. Walters, at 10.
[110] *Id.*, at 7.

authorized ROE of 9.25 percent which resulted in a reduction of approximately $20 million between the requested and approved revenue requirement; (2) the disallowance of certain expenses such as prepaid pension expenses; and (3) the decision to not adopt the annual rate review mechanism, which, if adopted, would have mitigated the effect of industrial customers scaling back production in response to changes in economic conditions.[111] Furthermore, Moody's noted that the disallowance of expenses already incurred resulted in Minnesota Power cutting operating expenses in order to earn the company's authorized ROE.[112] For these reasons, Moody's concluded that, while Minnesota Power has access to ratemaking mechanisms such as a forward test year and various riders, the ratemaking mechanisms are offset by the rate case outcome, which indicates a less than supportive regulatory relationship between Minnesota Power and the Minnesota Public Utilities Commission.[113]

Another example of the adverse consequences of low authorized ROEs is FitchRatings' (Fitch) recent downgrade of CenterPoint Energy Houston Electric's (CEHE) Long-Term Issuer Default rating from A- to BBB+ and revised rating outlook from Stable to Negative following the approval of an unfavorable outcome in a rate case in Texas. Fitch indicated that the unfavorable outcome signals a more challenging environment in Texas for CEHE and that the authorized ROE and equity ratio, as well as the tax reform refunds will create pressure on credit metrics. Fitch also indicated that further negative rating action could be possible if the company's FFO leverage remains above 5x.[114]

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[111] Moody's Investors Service, Credit Opinion: ALLETE, Inc. Update following downgrade, April 3, 2019, at 3.
[112] *Ibid.*
[113] *Ibid.*
[114] FitchRatings, Fitch Downgrades CenterPoint Energy Houston Electric to BBB+; Affirms CNP; Outlooks Negative, February 19, 2020.

According to a statement by S&P quoted by Mr. Walters, lower ROEs may be tolerated by utilities when they are successful in decreasing regulatory lag.[115] However, as shown in Attachment AEB-9DR, APS is not in a position to experience lower regulatory lag, compared to the utilities in its proxy group: APS uses historical test year (rather than forecasted test year used by 64 percent of the proxy group); and APS does not include CWIP in rate base (whereas 84 percent of its proxy group does).[116]

Q. DO YOU AGREE WITH MR. WALTERS' POSITION REGARDING MOODY'S REVISED OUTLOOK FOR APS?

A. No, I do not. Mr. Walters downplays the fact that, in January 2020, Moody's revised its outlook for APS down to negative from stable. He suggests that ratepayers should not pay for "negative actions made by APS" in the form of the Commission's authorized ROE for APS.[117] However, the fact is that only one of the two rationales cited by Moody's to explain the outlook revision relates to APS's relationship with regulators. Indeed, Mr. Walters quotes Moody's as expecting a "further decline in cash flow-based credit metrics" for APS.[118] The Moody's report states:

> …APS's negative rating outlook reflects the **potential for downward movement in the ratings if** the company's heightened capital expenditure program resulting from its clean energy investments or other **increases in leverage or reduction in cash flow result in a further deterioration of their credit metrics.** An indication that the Arizona regulatory environment has become less supportive, evidenced perhaps by the elimination of tracking or other mechanisms that reduce regulatory lag, or **an adverse ruling on its pending rate case, could also put downward pressure on the ratings.**[119]

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[115] Direct Testimony of Christopher C. Walters, at 10.
[116] Comparison is based on the 14-company proxy group in my Direct Testimony.
[117] Direct Testimony of Christopher C. Walters, at 20.
[118] *Id.*, at 19.
[119] Moody's Investors Service, Credit Opinion: Arizona Public Service Company, January 2020. (Emphasis added.)

If APS were to be authorized an ROE below its true cost of equity capital (out of a well-meaning intention to *protect* ratepayers), this could result in *harm* to ratepayers. An authorized ROE that is too low makes it more difficult for a utility to access the capital needed to invest properly in system safety and reliability.

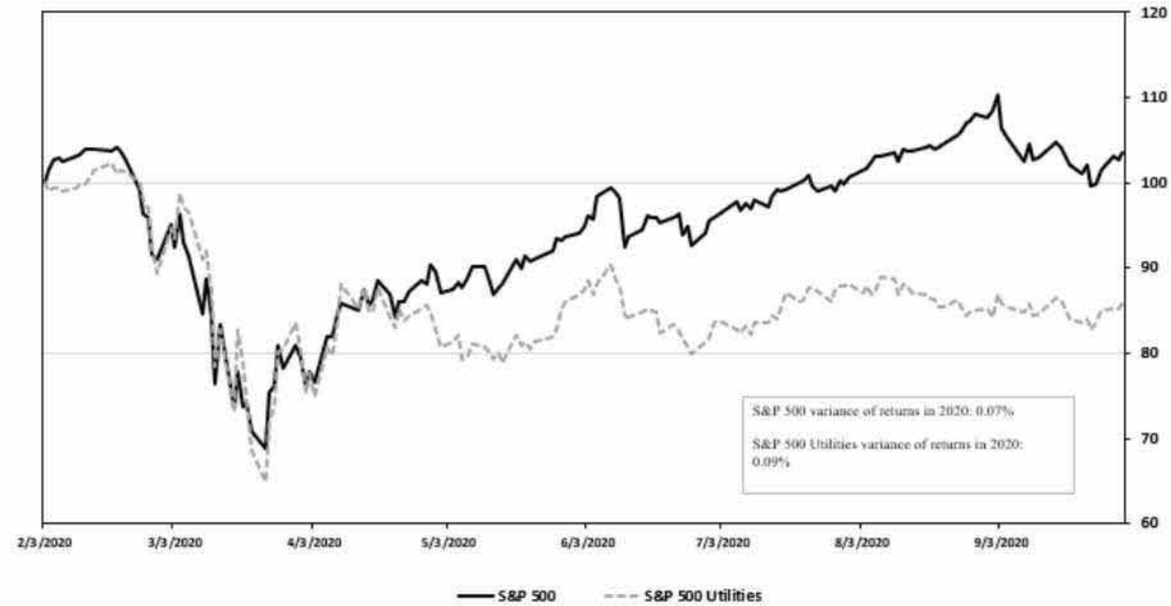
Q. WHAT IS YOUR RESPONSE TO MR. WALTERS' STATED ASSUMPTIONS ABOUT CURRENT UTILITY STOCK PRICES AND THEIR EFFECT ON ACCESS TO CAPITAL?

A. Mr. Walters asserts that utility valuations are "very strong and robust relative to the last several years,"[120] and he then reasons that such high valuations translate into easy access to equity capital for utilities. In response, I disagree somewhat with Mr. Walters' characterization of current utility valuations. In contrast to the market situation at the time of my Direct Testimony, utility stock prices have seen substantial market corrections. As shown further below in Figure 15, utility valuations are no longer at record peaks.

[120] Direct Testimony of Christopher C. Walters, at 9.

Figure 12: Comparison of the S&P 500 to

the S&P Utilities Index (January 1-September 30, 2020)



Q. WHAT IS YOUR RESPONSE TO MR. WALTERS' CAUTIONARY COMMENT REGARDING ADJUSTING THE COMPANY'S ROE DURING DIFFICULT ECONOMIC CONDITIONS?

A. Mr. Walters advises the Commission to be "concerned" about rate impacts related to its authorized ROE decision for APS, given current economic conditions.[121] However, a low authorized ROE could actually result in *higher* overall costs, given that APS would experience higher debt costs in the event of a credit rating downgrade. This risk is exacerbated by the current, tight credit metrics across the utility industry, which I have noted above. As I noted earlier in this section of my response to Mr. Walters, there exists ample evidence of actual adverse consequences of an authorized ROE below a utility's true cost of equity.

[121] *Id.*, at 13.

Q. PLEASE SUMMARIZE MR. WALTERS' POSITION ON INTEREST RATES.

A. As summarized in Figure 13, Mr. Walters uses a short-term projected risk-free rate of 1.80 percent to produce all nine of his CAPM results and one of his five Risk Premium model results (his other four results use current corporate bond yields as of September 2020).[122] In his FVI cost rate calculation, he uses long-term risk-free rate estimates of 3.00 percent, 3.80 percent, and 2.50 percent.

Q. WHAT INTEREST RATES HAVE YOU RELIED ON IN YOUR CAPM AND RISK PREMIUM MODELS?

A. Despite Mr. Walters' emphasis on the topic of interest rate assumptions in his critique of my Direct Testimony, he and I do not disagree on interest rates. Like Mr. Walters, I also use a short-term projected risk-free rate in my CAPM and Risk Premium models. However, as shown below in Figure 13, I make the more conservative (i.e., producing a lower numeric result) choice of using the average over the upcoming five quarters (1.64 percent), whereas Mr. Walters selects the figure for five quarters in the future (1.80 percent). In addition, in order to consider a full range of possibilities, I also produce CAPM and Risk Premium model results using the current risk-free rate (1.42 percent) and a long-term projected risk-free rate (3.00 percent). In my FVI cost rate calculation, I use precisely the same risk-free rate assumptions as Mr. Walters (i.e., 3.00 percent, 3.80 percent, 2.50 percent).

By observation, the yield on long-term government bonds has been increasing modestly in the weeks leading up to Mr. Walters' testimony filing date and is projected to increase markedly over the coming years. At the time I filed my Direct

[122] Mr. Walters uses 1.8% as the risk-free rate in his Risk Premium analysis (page 40: 7.02+1.8=8.8) and in his CAPM analysis (page 43). However, elsewhere, he mistakenly states that his risk-free rate is 1.9% (page 72: 7.02+1.9=8.9). His 1.8% assumption represents the Blue Chip projection of long-term Treasury bond yields as of 9/1/20 (page 43); however, elsewhere he states that rates are expected to "decline to 1.9%" by Q4 2021 (page 14).

Testimony over a year ago—which was prior to the COVID-19 pandemic and its effects on financial markets—interest rates and interest rate projections were obviously quite different than they are today.

Q. DOES MR. WALTERS AGREE THAT INTEREST RATES ARE PROJECTED TO INCREASE?

A. Yes, he does. It is notable, however, that Mr. Walters displays some confusion over interest rate trends through the course of his testimony. As summarized above and also shown below in Figure 13, his modeling assumptions demonstrate a projected increase in interest rates (the current 30-year Treasury bond yield is 1.42 percent, whereas he uses a projection of 1.80 percent in his models). Despite his modeling assumptions, his written testimony asserts that 30-year Treasury bond yields are "expected to remain flat to slightly declining to a level near 1.9% through the fourth quarter of 2021."[123]

[123] Direct Testimony of Christopher C. Walters, at 13-14. His Table 4 (at 14) presents figures that contradict his statement.

Figure 13: Risk-free interest rate assumptions (30-year Treasury bond yield)

	Walters Direct Testimony filed October 2, 2020	Bulkley Rebuttal Testimony
Current	N/A[124]	1.42% (Actual average of 30 days ending 9/30/20)
Short-term projected	1.80% (Projected for Q4 2021 as of September 2020)	1.64% (Projected average over Q4 2020-Q4 2021 as of 9/1/20)
Long-term projected[125]	3.00% (Projected average over 2022-2026 as of 6/1/20) 3.80% (Projected average over 2027-2031 as of 6/1/20)	Same as Walters

Q. HAS MR. WALTERS RECOGNIZED THE EFFECT THAT CHANGES IN MARKET CONDITIONS CAN HAVE ON THE RESULTS OF ROE ESTIMATION MODELS?

A. Yes. First, as a reasonableness check, Mr. Walters compares his MRP range used in the CAPM to three MRP estimates produced by Duff & Phelps, including an MRP estimate based on an *ex-post* supply side model developed by Roger Ibbotson and Peng Chen (Ibbotson and Chen).[126] This model is based on the historic supply of equity returns, which considers inflation, income return, growth in real earnings per share and growth in the P/E ratio. Mr. Walters notes, however, that Ibbotson and Chen made an adjustment to the model to reflect that the historical level of growth in P/E ratios is not expected to continue into the future.[127]

[124] Mr. Walters does not use a current Treasury bond yield to produce any of his ROE model results, but he notes in Attachment CCW-15DR that, as of September 18, 2020, the historical average 13-week average yield on 30-year Treasury bonds was 1.37% and the 26-week average was 1.36%.
[125] Both Mr. Walters and I also use the Duff & Phelps "normalized" (i.e., "estimated sustainable average") 20-year Treasury yield of 2.5% (as of 6/30/20) in one scenario of the FVI cost rate calculation.
[126] Direct Testimony of Christopher C. Walters, at 57 and 49.
[127] *Id.*, at 57-58 and 49.

Second, in his specification of the CAPM, Mr. Walters relies on an average of Beta estimates published in past years (rather than current Beta estimates) because he believes that market conditions cause the current Beta to be "abnormally" high.[128,129]

By considering Ibbotson and Chen's MRP estimate, and by taking the unusual step to rely on outdated Beta estimates rather than the latest published estimates, Mr. Walters appears to acknowledge that the results of ROE estimation models can and have been affected by market conditions.

B. *Growth Rates in DCF Model and Relevance of Results*

Q. PLEASE SUMMARIZE MR. WALTERS' DCF ANALYSIS RESULTS.

A. Mr. Walters conducts three DCF analyses: two analyses using a Constant Growth DCF model, and one analysis using a Multi-Stage DCF model.

One version of his Constant Growth DCF uses analysts' projected earnings growth estimates and the other version uses a measure of "sustainable growth."[130] His Multi-Stage DCF model uses analysts' projected earnings growth rates in Stage 1 (years 1-5)[131] and a growth rate of 4.24 percent in Stage 3 (year 11 onward) to represent projected GDP growth;[132] the growth rate in Stage 2 (years 6-10) transitions between the Stage 1 and Stage 3 growth rates.

He uses the same proxy group that I relied on in my Direct Testimony. Figure 14 below summarizes the results of his DCF models.

[128] *Id.*, at 44.
[129] *Id.*, at 55.
[130] *Id.*, at 24-25.
[131] *Id.*, Attachment CCW-4DR.
[132] *Id.*, Attachment CCW-10DR.

Figure 14: Summary of Walters DCF model results[133]

Model Structure	Growth Rate Assumption	Mean ROE Result
Constant Growth	Analyst estimates of earnings growth rate	9.47%-9.50%
Constant Growth	Calculated "sustainable growth rate"	9.17%-9.18%
Multi-Stage	Analyst estimates of earnings growth rate (first 5 years) + Projected GDP growth rate (> year 10)	8.64%-8.67%

The range of mean results from the DCF analyses prepared by Mr. Walters is 8.64 percent to 9.50 percent. Mr. Walters concludes that his DCF studies support an ROE of 9.10 percent.

Q. HOW DOES MR. WALTERS WEIGH THE RESULTS OF HIS THREE DIFFERENT DCF MODEL VERSIONS?

A. Mr. Walters does not explain how he arrives at his judgment that a 9.10 percent ROE is appropriately representative of his DCF model results. Nonetheless, one can infer arithmetically that, in order to support the 9.10 percent number, Mr. Walters must be attributing some value to the output of the version of his Constant Growth DCF model that relies on analysts' EPS growth rates. At the same time, arithmetically, he must be attributing some value to the output of his Multi-Stage DCF model, even though it produces results well below the ROE authorized for any vertically integrated electric utility since January 2018 (as shown in Figure 2 in Section III of this Rebuttal Testimony).[134]

[133] *Id.*, Table 7, at 35.
[134] Source: Regulatory Research Associates.

Q. WHAT DIVIDEND YIELD DOES MR. WALTERS RELY ON IN HIS CONSTANT GROWTH DCF MODELS, AND HOW DOES THAT INPUT AFFECT HIS DCF RESULTS?

A. The average adjusted dividend yield for Mr. Walters' APS proxy group ranges from 4.19 percent (in the Constant Growth DCF model using "sustainable growth rates" and 26-week stock prices) to 4.22 percent (in the Constant Growth DCF model using analysts' projected earnings growth rates and 13-week stock prices). As discussed in my Direct Testimony, recent market conditions drove utility stock prices higher and dividend yields lower.[135] While there has been a correction to utility stock prices in 2020, as noted in Section V of this Rebuttal Testimony, analysts still perceive utility stocks to be priced higher than historical norms. Therefore, the average dividend yields for the proxy group companies remain below historical average levels. As a result, DCF models continue to produce understated results at this time, due to the effect of current market conditions on dividend yields of utility stocks. As Value Line explained recently, valuations on utility shares are still elevated compared to historical levels.[136] This could result in an under-estimation of the forward-looking cost of equity using the DCF model, especially if those high valuations are not sustainable in the future.

Q. DO YOU AGREE WITH MR. WALTERS' ESTIMATES OF THE PROXY GROUP'S "SUSTAINABLE GROWTH RATE" IN HIS DCF ANALYSES?

A. No, I do not. First, Mr. Walters' calculated "sustainable growth rates" for the APS proxy group do not correspond logically to the growth rates that analysts project for the timeframe that APS rates set in this proceeding will be in effect. For example, Value Line's three- to five-year implied ROE[137] for the proxy group

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[135] Direct Testimony of Ann E. Bulkley, at 13-14.
[136] Value Line Investment Survey, Electric Utility (Central) Industry, June 12, 2020, at 901.
[137] Value Line's implied ROE = Value Line's projected Earnings Per Share / Value Line's projected Book Value Per Share.

(which Mr. Walters uses as a key input to his "sustainable growth" DCF models) equals 10.71 percent.[138] However, the ROE output from Mr. Walters' "sustainable growth" models is 153-154 basis points *lower* than that projection.[139]

In addition, I will note that, in the context of the "sustainable growth" version of his Constant Growth DCF model, Mr. Walters asserts that the "long-term sustainable growth rate"[140] equals 4.97 to 4.98 percent.[141] Meanwhile, in the context of his Multi-Stage DCF model, Mr. Walters asserts that the "long-term sustainable growth rate"[142] equals 4.24 percent.[143] Mr. Walters does not offer an explanation for this difference.

Q. ACCORDING TO MR. WALTERS, THE ANALYST GROWTH RATES USED IN YOUR DCF ANALYSIS ARE OVERSTATED.[144] WHAT IS YOUR RESPONSE?

A. Both Mr. Walters and I use EPS growth rates that represent consensus forecasts of analysts surveyed by Thomson First Call and Zacks Investment Research. Those growth rates should be the same since they are from the same sources. Unlike Mr. Walters, I also include growth rate estimates from Value Line in my analysis. To the extent that Mr. Walters has concerns with the analyst growth rates used in my DCF model, those same concerns would apply to his model. Furthermore, as shown in Attachment CCW-5DR, the average analysts' earnings growth rate for Mr. Walters' proxy group is 5.27 percent, which is entirely consistent with the average growth rate relied upon in my Constant Growth DCF analyses (which have been updated to reflect current data through September 2020).

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[138] Direct Testimony of Christopher C. Walters, Attachment CCW-7DR, at 1.
[139] *Id.,* Attachment CCW-8DR.
[140] *Id.*, at 27.
[141] *Id.*, at 28.
[142] *Id.*, at 29.
[143] *Id.*, at 35.
[144] *Id.*, at 59.

Q. ARE THE ROE ESTIMATES PRODUCED BY MR. WALTERS' CONSTANT GROWTH DCF MODELS COMPARABLE TO THE RETURNS AVAILABLE TO INVESTORS IN COMPANIES WITH SIMILAR RISK?

A. No. As shown in Mr. Walters' Attachment CCW-8DR, the ROE estimates produced by the variation of his Constant Growth DCF model that uses "sustainable growth rates" range from 5.9 percent to 14.3 percent. And, for example, his result for Evergy is only 5.9 percent, which is not a reasonable estimate of the cost of equity.[145]

Q. DO YOU AGREE WITH MR. WALTERS THAT IT IS MORE APPROPRIATE TO USE THE MEDIAN WHEN OUTLIERS ARE IDENTIFIED THAN TO EXCLUDE INDIVIDUAL RESULTS BELOW 7.00 PERCENT?[146]

A. I agree with Mr. Walters that the median is the appropriate measure of central tendency to rely on when outliers have been identified. However, it is also appropriate for an analyst to consider the reasonableness of the data. As shown in Attachment AEB-1DR, the individual results that I removed from the Constant Growth DCF analysis presented in my Direct Testimony ranged from 5.99 percent to 6.67 percent. It is clear that those numbers do not properly reflect the risk of common equity. Additionally, it should be noted that the individual results I removed were lower than the results from all three of Mr. Walters' DCF analyses.

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[145] *Id.*, Attachment CCW-8DW, at 1.
[146] *Id.*, at 60.

Q. DO OTHER JURISDICTIONS IMPOSE AN OUTLIER TEST ON THE RESULTS OF THE DCF MODEL?

A. Yes, they do. In Opinion No. 569-A, FERC affirmed the use of outlier tests as a reasonable approach for addressing results that are too low to be reasonably considered in any measure of central tendency.[147]

Q. DO YOU AGREE WITH MR. WALTERS' CHARACTERIZATION OF THE CURRENT MARKET SENTIMENT REGARDING UTILITY INVESTMENTS?

A. No, I do not. Mr. Walters suggests that utilities have benefited from high valuations on utility stocks and that the market recognizes the low risk characteristics of this industry, suggesting it has generally been regarded as a safe haven by the investment industry.[148] However, Mr. Walters provides no support for these statements. And the statements do not appear to reflect current market conditions.

For example, his characterization of the industry as a low-risk industry is contradicted by the Betas that have recently been experienced by this sector. As discussed in Section V of this Rebuttal Testimony, in recent market conditions, utilities have not been viewed by analysts as safe-haven investments. In fact, as shown in Figure 12, above, utilities have traded with similar volatility to the broader market, while nonetheless underperforming the broader market, since the beginning of the pandemic.

Additionally, Mr. Walters' assessment of market conditions conflicts logically with the Beta assumptions he considers in his CAPM analysis. As Mr. Walters notes, Beta is a measure of the non-diversifiable risk of a security. The market overall has a Beta of 1.0, and companies with Betas lower than 1.0 are considered to have less non-diversifiable risk than the overall market, while those with Betas

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[147] Federal Energy Regulatory Commission, Opinion No.569-A, May 21, 2020, at p. 66.
[148] Direct Testimony of Christopher C. Walters, at 76.

greater than 1.0 have more non-diversifiable risk. In Attachment CCW-16DR, Mr. Walters reports the current Value Line Betas for APS proxy companies,[149] but he also suggests that these Betas are "abnormally high and are unlikely to be sustained over the long-term."[150] If Mr. Walters believes that the current Betas for utilities are too high, logically he cannot also believe that utility stocks bear less risk and are safe-haven investments.

Q. DID YOU EXAMINE THE EFFECT OF HIGH VALUATIONS ON THE DIVIDEND YIELDS OF UTILITY STOCKS?

A. Yes. As shown in Figure 15, to illustrate the effect of high valuations on the dividend yield, I calculated the correlation coefficient between the annual average P/E ratio and dividend yield for the 14-company proxy group used by Mr. Walters and the period reported in Exhibit CCW-2DR: 2002 through 2020. The correlation coefficient for those 18 years is negative 0.85. As expected, this indicates a high degree of correlation between the dividend yield and P/E ratio.[151] That the correlation coefficient is negative indicates, that, as the P/E ratio increases (decreases), the dividend yield decreases (increases). Therefore, if the valuation of utilities declines over the near-term, as projected by Value Line, the proxy group dividend yields and therefore the estimate of the ROE produced by the DCF model will increase. Thus, the data provided by Mr. Walters supports my conclusion that, under current market conditions, the DCF model is understating the forward-looking cost of equity. As a result, it is important to: 1) consider the results of the DCF model with caution; 2) rely on the results of multiple ROE estimation models in determining the appropriate ROE; and 3) use forward-looking inputs where possible to account for changing market conditions.

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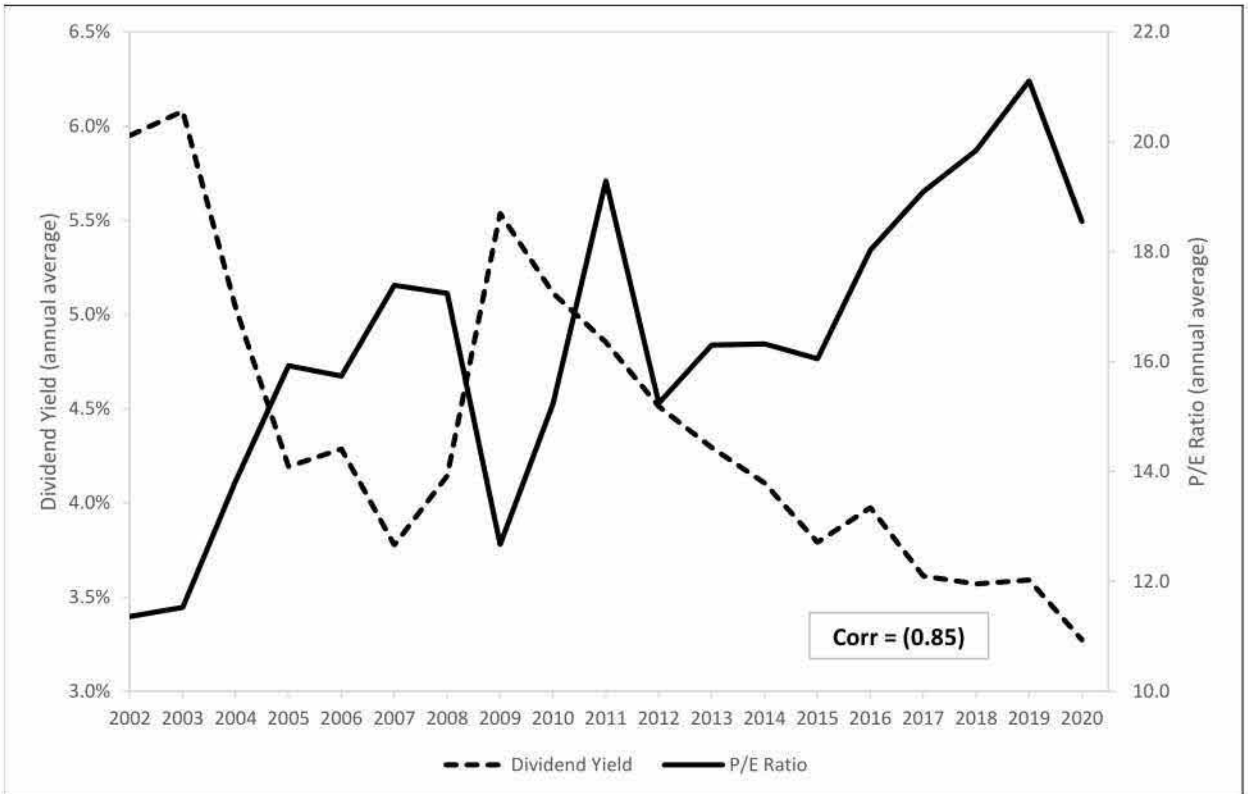
[149] Value Line calculates Betas using five years of historical data.
[150] Direct Testimony of Christopher C. Walters, at 43.
[151] A correlation coefficient with an absolute value of 0.8 or higher indicates a very strong relationship.

Figure 15: P/E Ratios and Dividend Yields for APS Proxy Group[152]

(January 1, 2002 – September 30, 2020)



Q. DO YOU AGREE WITH MR. WALTERS THAT THE FORECASTED STOCK PRICES IN YOUR PROJECTED DCF MODEL DO NOT REFLECT THE VIEWS OF INVESTORS?[153]

A. No, I do not. The purpose of the Projected DCF analysis is to illustrate the effect that an increase in interest rates or a decline in electric utility stock prices would have on the cost of equity during the period that APS's rates will be in effect.

Value Line's outlook is consistent with other equity analysts and investment advisors' expectations of the overall market. As discussed in Section V of my Rebuttal Testimony, the valuations of utility stocks have been well above the long-

[152] Reflects the 14-company proxy group used by Mr. Walters and presented in my Direct Testimony.
[153] Direct Testimony of Christopher C. Walters, at 70-71.

term averages because investors have driven up the share price of utilities, resulting in a reduction in the dividend yield. In 2020, those valuations have declined considerably (as shown in Figure 15 above). However, analysts still believe that utility stocks valuations are higher relative to historical levels. If utility valuations continue to decline as expected, the dividend yield of utilities will increase. Thus, the cost of equity estimated by DCF models will increase. Using the projected stock prices developed by Value Line, it is possible to illustrate this effect.

Q. WHAT ARE YOUR OVERALL CONCLUSIONS REGARDING MR. WALTERS' DCF RESULTS?

A. My conclusions with respect to Mr. Walters' DCF results are twofold.

First, just as utility Betas have been affected by recent market activity (which Mr. Walters acknowledges), utility stock prices and dividend yields relied on by Mr. Walters for his DCF models have been affected by the same market conditions (though he fails to acknowledge this). As a result of these market conditions, Mr. Walters' DCF models understate the forward-looking cost of equity.

Second, the results of Mr. Walters' "sustainable growth" DCF analysis and Multi-Stage DCF analysis are below the return that can be expected by an investor on an alternative investment of comparable risk. Those results are well below the average returns that have been recently authorized for vertically integrated electric utilities.

C. *Development and Application of Bond Yield Plus Risk Premium model*

Q. HOW DOES YOUR BOND YIELD PLUS RISK PREMIUM APPROACH DIFFER FROM THAT OF MR. WALTERS?

A. Mr. Walters and I fundamentally disagree on the proper methodology for a Bond Yield Plus Risk Premium approach to estimating expected ROE.

Mr. Walters and I agree that the first step for this approach is to analyze historical implied equity risk premia (which are calculated as the difference between historical authorized ROEs and historical bond yields). Mr. Walters and I also agree that the relationship between that implied equity risk premium and contemporaneous bond yields somehow "changes over time."[154] However, Mr. Walters and I disagree as to *how* to reflect that changing relationship in our calculations. On the one hand, Mr. Walters uses the simple average relationship from the last five years, and he merely adds that static single number to a current and/or projected bond yield. By contrast, I develop a regression analysis describing the dynamic relationship over a significantly longer period of time, and I input a current and/or projected bond yield into that equation. The similarities and differences between our methodologies are summarized below in Figure 16.

[154] *Id.*, at 82-83.

Figure 16: Comparison of Walters and Bulkley methodology for Bond Yield Plus Risk Premium approach to estimating expected ROE

	Walters	Bulkley
Historical implied equity risk premium	Historical authorized ROE *LESS* historical bond yield	Same as Walters
Time period over which relationship between implied equity risk premium and bond yield is analyzed	5 years ending June 2020	28 years ending September 2020
Current/projected equity risk premium	Static single number (simple average)	Dynamic output of an equation (linear regression formula with R-squared of 0.8)
Bond yield	2.56% only	Any current/projected 30-year Treasury bond yield
Expected ROE	Current/projected equity risk premium *PLUS* current/projected bond yield	Same as Walters

The benefit of conducting a regression analysis is that the resulting predictive equation can be used to estimate a going-forward equity risk premium corresponding to *any* interest rate one wishes to specify. By specifying the interest rate projected for the time period that APS's rates from this proceeding will be in effect, one thus can estimate an equity risk premium (and thus an ROE) for the time period that APS's rates will be in effect.

In contrast, with Mr. Walters' methodology, he is limited to estimating a going-forward equity risk premium based only on the average interest rate for the last five years (equal to 2.56 percent, in the case of his 30-year Treasury bond yields). If he specifies a different interest rate (which he does), he invalidates his own results by having failed to account for the dynamic relationship between risk premia and interest rates.

Therefore, I believe it is more appropriate to use a regression analysis, rather than Mr. Walters' method of summing a *projected* interest rate and a fixed, *historical* implied equity risk premium.

Q. PLEASE SUMMARIZE MR. WALTERS' BOND YIELD PLUS RISK PREMIUM MODEL RESULTS.

A. Mr. Walters conducts two analyses: one based on utility equity risk premia relative to 30-year Treasury bonds, and one based on utility equity risk premia relative to utility bonds. In the first case, Mr. Walters estimates an ROE of 8.8 percent by adding the average implied equity risk premium over 30-year Treasury bonds from the last five years (7.02 percent) to his short-term projected yield on 30-year Treasury bonds (1.80 percent). In the second case, Mr. Walters estimates ROEs of 8.7 percent and 9.2 percent by adding the average implied equity risk premium over utility bonds from the last five years (5.74 percent) to current yields (last 26-week average[155]) on A-rated (3.00 percent) and Baa-rated (3.42 percent) utility bonds.[156] From this range of three results, Mr. Walters defines a reasonable ROE as 9.0 percent.[157]

Q. PLEASE COMMENT ON MR. WALTERS' CHOICE TO USE A FIVE-YEAR HISTORICAL PERIOD TO ANALYZE AUTHORIZED ROES AND THEIR IMPLIED EQUITY RISK PREMIA.

A. Mr. Walters considers using either a five-year or ten-year average utility equity risk premium from anywhere across the 1986 to 2020 period.[158] He ultimately elects to use the most recent five-year period average. He explains that he chose that period because it has the highest risk premium—which is his acknowledgement of the current low interest rate environment (and, implicitly, of the dynamic that low

[155] Although Mr. Walters presents 13-week and 26-week averages, he apparently uses the 26-week figure when doing the arithmetic to produce an ROE estimate.
[156] Direct Testimony of Christopher C. Walters, at 40.
[157] *Id.*, at 41.
[158] *Id.*, at 37.

interest rates correlate to higher equity risk premia).[159] Moreover, Mr. Walters takes the five-year average of his annual averages (where each year's average represents a dozen or two authorized ROE decisions), thus distancing himself from the underlying data.

For example, had Mr. Walters relied on the underlying data—rather than averages—he might have noticed that the utility equity risk premium has increased from 2018 to date (as shown on his Attachment CCW-12DR). Acknowledging that the equity risk premium changes over time, it would be more appropriate to rely on the equity risk premium that reflects current market conditions rather than an average that takes into consideration historical market conditions.

Q. DOES YOUR INTEREST RATE ASSUMPTION IN YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS DIFFER MEANINGFULLY FROM THAT OF MR. WALTERS?

A. No. While Mr. Walters and I fundamentally disagree on Bond Yield Plus Risk Premium *methodology*, our individual assumptions about interest rates do not contribute meaningfully to differences in our ROE results. Mr. Walters and I both use a short-term projected 30-year Treasury bond yield to calculate an ROE via the Bond Yield Plus Risk Premium method. He opts to use the yield projected for Q4 2021 (1.80 percent, as of September 2020), while I more conservatively opt to use the average of yields projected for each of the five quarters Q4 2020 through Q4 2021 period (1.64 percent, as of September 1, 2020). In order to consider a wider range of scenarios, I also produce ROE estimates using the current 30-year Treasury bond yield and a long-term projected Treasury bond yield. These assumptions are summarized and further detailed above in Figure 13 in Section A of my response to Mr. Walters.

[159] *Id.*, at 40.

Mr. Walters also produces Risk Premium model results by adding a historical risk premium to current utility bond yields.

Q. PLEASE SUMMARIZE AND RESPOND TO MR. WALTERS' POSITION REGARDING THE RELATIONSHIP BETWEEN EQUITY RISK PREMIA AND INTEREST RATES.

A. Mr. Walters disputes the inverse relationship between interest rates and equity risk premia.[160] Indeed, he characterizes the inverse relationship that is used in my Bond Yield Risk Premium analysis as "simplistic"[161] and my methodology as "flawed."[162] He goes on to claim that, while academic studies have shown that an inverse relationship has existed in the past, the relationship has changed over time—particularly since interest rate volatility is not as extreme as it was in the 1980s.[163]

This is a curious argument for several reasons, including the fact that Mr. Walters seems to acknowledge the inverse correlation between interest rates and equity risk premia when he explains how he selected the five-year historical time period for his analysis (as I discuss above).

With regard to Mr. Walters' statement that interest rate volatility was more extreme in the 1980s than it is today, I conducted an analysis that compares the volatility in 30-year Treasury bond yields in each year during the 1980s to the volatility in 2019 and 2020. As shown in Figure 17, the relative standard deviation of Treasury bond yields is substantially higher in 2019 and 2020 than it was during any year in the 1980s, indicating that interest rate volatility is higher now than it was in the 1980s.

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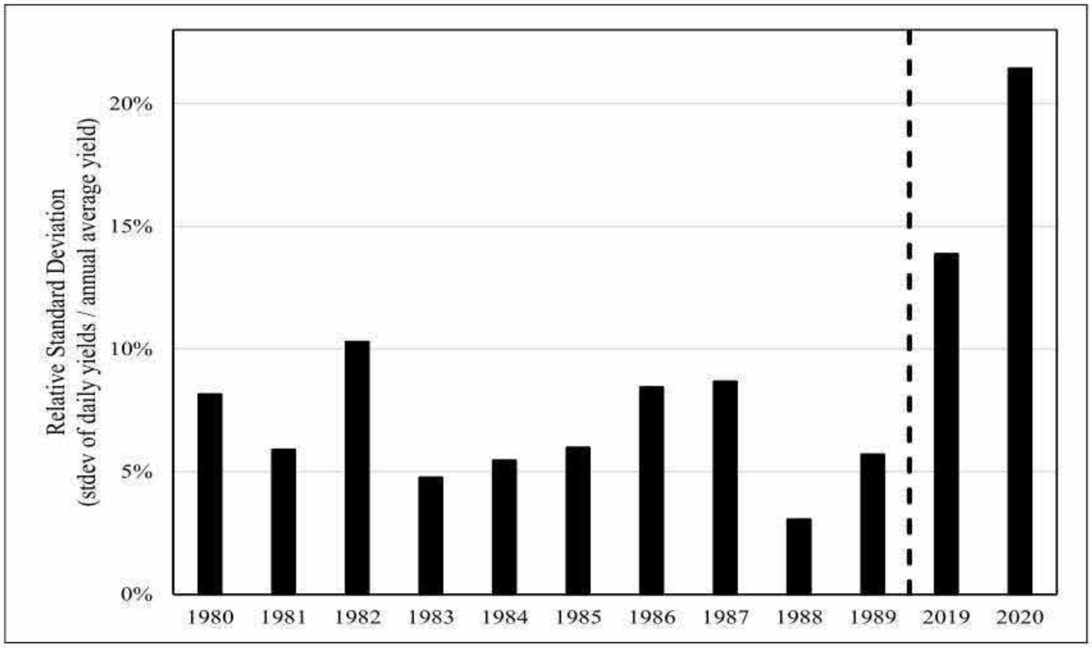
[160] *Id.*, at 69.
[161] *Ibid.*
[162] *Id.*, at 70.
[163] *Id.*, at 69.

Figure 17: Treasury Bond Yield Volatility[164]



With respect to Mr. Walters' position against an inverse relationship between equity risk premia and interest rates, he fails to recognize that a large body of research (in addition to my own statistical analyses) supports that inverse relationship. That large body of research includes the March 1998 article published by Dr. S. Keith Berry which came to similar conclusions regarding the inverse relationship between interest rates and the risk premia.[165] Although Mr. Walters cites some studies as evidence that this inverse relationship is a relic of the 1980s, several other studies were published thereafter. As summarized in *New Regulatory Finance*, many of these studies were published in 2005, demonstrating that the inverse relationship between interest rates and the equity risk premium is a contemporary concept in finance:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates—rising when rates fell and

[164] Data for 2020 is through September 30.
[165] *See* Direct Testimony of Ann E. Bulkley, at 50.

> declining when interest rates rose. The reason for this relationship is that when interest rates rise, bondholders suffer a capital loss. This is referred to as interest rate risk.... Conversely in low interest rate environments, when bondholders' interest rate fears subside and shareholders' fears of loss of earning power dominate, the risk differential will widen and hence the risk premium will increase.[166]

Furthermore, my regression analysis has an R-squared of approximately 0.80,[167] which means that 80 percent of the variation in historical implied utility equity risk premia can be explained by changes in interest rates. My results indicate that there indeed exists a strong negative correlation between utility equity risk premia and interest rates.

Q. DOES MR. WALTERS DEMONSTRATE AN ACCURATE UNDERSTANDING OF THE CONCEPT OF REGRESSION ANALYSIS?

A. No, he does not. Mr. Walters asks himself the question as to whether my "regression study" demonstrates "cause and effect between interest rates and equity risk premiums."[168] This is a curious question, given that regression analysis is used to identify and quantify *correlation*, by testing how well independent variable(s) explain variation in a dependent variable. It does not measure or prove *causation*. And I have not claimed that it does.

Mr. Walters argues that authorized ROEs are "not directly adjusted by market forces."[169] But this is an uncontroversial statement of fact with which I agree. Indeed, in the course of determining the ROE to be authorized in any proceeding, utility regulators review many types of market data from various sources, consider many representations about equity investor requirements and expectations, and take into account idiosyncratic risks faced by subject utilities. Thus, the causal link

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[166] Morin, Roger A., New Regulatory Finance, Public Utilities Reports, Inc. (2006), at 128.
[167] Direct Testimony of Ann E. Bulkley, at 49.
[168] Direct Testimony of Christopher C. Walters, at 70.
[169] *Ibid*.

between interest rates and authorized ROEs is, by definition, both indirect and complex.

It remains the case, as I stated above, that my regression model demonstrates a strong negative correlation between utility equity risk premia and interest rates. Given my regression model's high degree of explanatory power, it is entirely valid and useful to employ it to predict the value of the dependent variable (i.e., the utility equity risk premium) based on a specified value of the independent variable (i.e., a current and/or projected risk-free interest rate).

Q. IS MR. WALTERS' CRITIQUE OF YOUR RISK PREMIUM METHODOLOGY CONSISTENT WITH HIS OWN APPROACH?

A. No, it is not. Mr. Walters erroneously claims that I believe there is a "simplistic" relationship between utility equity risk premia and interest rates. In fact, I believe the relationship is complex enough to warrant developing a regression model to describe it, whereas Mr. Walters appears to be content with manipulating simple averages and mixing time periods. Mr. Walters plainly acknowledges that the relationship between interest rates and equity risk premia "changes over time."[170] Despite that acknowledgement, Mr. Walters fails to account for (or even explain his reason for failing to account for) any dynamic relationship between the two variables in his own Risk Premium analysis.

Q. PLEASE PROVIDE AN EXAMPLE OF HOW MR. WALTERS' BOND YIELD PLUS RISK PREMIUM ANALYSIS UNDERESTIMATES EXPECTED ROE.

A. Mr. Walters produces one of his three ROE estimates (8.8 percent) based on the average implied equity risk premium over 30-year Treasury bonds from the last five years (7.02 percent). As can be calculated from his Attachment CCW-12DR, the average yield on 30-year Treasury bonds over those same last five years was

[170] *Id.*, at 69.

2.56 percent. However, Mr. Walters uses a short-term projected interest rate assumption of only 1.80 percent in his calculation. Given the inverse relationship between interest rates and the risk premia, it is reasonable to assume that a *lower* yield on Treasury bonds would correspond to a *higher* risk premium. In fact, Mr. Walters' own data supports such a conclusion: for example, as shown in his Attachment CCW-12DR, the average 30-year Treasury bond yield for the first part of 2020 was 1.63 percent (i.e., lower than the five-year average of 2.56 percent) while the risk premium was 7.84 percent (i.e., higher than the five-year average of 7.02 percent). Following Mr. Walters' own methodology, one could logically sum that more recent risk premium of 7.84 percent with his Treasury bond yield assumption of 1.80 percent to produce an ROE of 9.64 percent (in contrast to his 8.8 percent). Thus, it is clear that Mr. Walters' Bond Yield Plus Risk Premium analysis underestimates the expected ROE and, accordingly, APS's cost of equity.

D. *Inputs and Assumptions of CAPM model*

Q. HOW DOES YOUR CAPM APPROACH DIFFER FROM THAT OF MR. WALTERS?

A. Mr. Walters and I use the same methodology for our CAPM analyses. We differ regarding assumptions for the risk-free rate, the proxy group Beta, and the MRP.

Q. PLEASE SUMMARIZE MR. WALTERS' CAPM ANALYSIS RESULTS.

A. Mr. Walters produces nine different ROE estimates from his CAPM analysis, reflecting three different estimates of the proxy group Beta and three different estimates of the MRP. His results range from 8.31 to 12.16 percent.[171] From this range of nine results, Mr. Walters defines a reasonable ROE as 9.6 percent.[172]

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[171] *Id.*, at 50-51.
[172] *Id.*, at 51.

Q. HOW DO YOU AND MR. WALTERS DIFFER REGARDING THE RISK-FREE RATE ASSUMPTION?

A. Mr. Walters states that the second of his "two primary issues"[173] with my CAPM results is my use of a projected interest rate. He quite emphatically asserts that my "reliance on projected interest rates is unreasonable."[174] But, meanwhile, Mr. Walters explicitly uses a projected interest rate in his own CAPM analyses. Regarding the risk-free interest rate assumption in the CAPM equation, Mr. Walters uses the short-term projected yield on 30-year Treasury bonds in all nine of his model variations. Specifically, he selects the rate projected by Blue Chip Financial Forecasts (Blue Chip) for Q4 2021 as of September 2020 (1.80 percent). Like Mr. Walters, I, too use Blue Chip's projected yield on 30-year Treasury bonds; however (as I discussed in Section A of my response to Mr. Walters), I use the average of Q4 2020 through Q4 2021 projections (1.64 percent, as of 9/1/20), rather than the individual quarterly projection only for Q4 2021 (1.80 percent).

Q. DO YOU CONSIDER OTHER RISK-FREE RATE ASSUMPTIONS?

A. Yes, I do. In contrast to Mr. Walters, who in fact uses only projected risk-free interest rates in all his CAPM versions, I consider the current risk-free rate in some of my CAPM analyses. Again, with this choice I am being even more conservative than Mr. Walters. I will note that—while Mr. Walters relies on projected rates in his CAPM while inconsistently criticizing the use of projections in my analysis—my CAPM scenario using the current risk-free rate (1.42 percent for the 30 days ending September 30, 2020) still exceeds an 11.0 percent ROE. Therefore, the use of projected interest rates is not the explanation of the differences in our analyses.

I also calculate the CAPM using a projected risk-free interest rate over a longer term, which may more closely match the period when APS's rates from this

[173] *Id.*, at 62.
[174] *Id.*, at 62 and 77.

proceeding will be in effect. That projected rate was 3.60 percent (for 2021-2025) when I filed my Direct Testimony, and as of June 1, 2020 it is now 3.00 percent (for 2022-2026).

Q. PLEASE SUMMARIZE AND RESPOND TO MR. WALTERS' ASSUMPTIONS REGARDING THE PROXY GROUP BETA.

A. Mr. Walters uses three different published estimates of Beta for the 14 individual proxy group companies: (1) Value Line's adjusted Betas as of September 11, 2020, (2) the average of Value Line's adjusted Betas published quarterly from Q3 2014 through Q2 2020, and (3) S&P Global Market Intelligence's raw Betas as of September 18, 2020.[175] I will refer to these as Mr. Walters' Beta estimates #1, #2, and #3. For each of these three data sets, Mr. Walters calculates the average Beta of the 14-company proxy group: 0.89, 0.72, and 0.69, respectively.

Mr. Walters' Beta estimate #2 (obtained from past Value Line publications) is not defensible. By its definition, the CAPM equation demands an assumption for what market participants *currently* view as the subject company's Beta (a view which, of course, they select some period of historical data to develop)—not what their *previous* views may have been. Estimates of Beta that market participants had produced in prior years—and which have since been superseded with their updated estimates of Beta—are simply not relevant to the CAPM's aim of calculating investors' prospective required return on equity.

Mr. Walters' Beta estimate #3 (obtained from S&P Global Market Intelligence) is also not defensible, for two reasons:

[175] *Id.*, at 44.

1. Mr. Walters erroneously refers to the S&P published Betas as "adjusted"[176] when they are in fact raw Betas.[177] Adjusting them as per the adjusted Betas published by Value Line changes the S&P Beta from 0.691 to 0.793 (i.e., 0.691*0.67 + 1*0.33).[178] However, manually-adjusted S&P raw Betas are still not directly comparable to Value Line (or Bloomberg) adjusted Betas, as explained below.

2. The Betas published by S&P Market Intelligence are calculated using a *daily* return interval,[179] while the Betas published by Value Line (and Bloomberg) are calculated using a *weekly* return interval.[180] This is a consequential distinction, given the "frequency dependence of Beta" commonly known to financial market participants. In fact, selection of a shorter return interval (e.g., daily rather than weekly) biases Beta estimates downward for many companies (such as those in APS's proxy group), making them appear less risky than they really are.

A 2014 academic paper provides a helpful summary of the long history of inquiry on this topic:

> Prior research has attributed the frequency dependence of measured beta to firm size, (e.g., Roll 1981; Hawawini 1983; Handa, Kothari, and Wasley 1989), microstructure frictions such as nonsynchronous trading (e.g., Scholes and Williams 1977; Dimson 1979; Lo and MacKinlay 1990) and bid-ask bounce (e.g., Blume and Stambaugh

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[176] *Ibid*.

[177] S&P's Beta calculation method is explained on their website at: https://platform.marketintelligence.spglobal.com/help/HelpFile/Data_Conventions_and_Ratio_Methodology.htm

[178] Mr. Walters states that the proxy group average (raw) S&P Beta equals "0.69." However, to reproduce his CAPM results, one must use the unrounded average of 0.691, which I computed from the individual company Betas he provides in CCW-16DR.

[179] *See* S&P's Beta calculation method as explained on their website.

[180] How to Invest in Common Stocks: The Complete Guide to Using the Value Line Investment Survey. Value Line Publishing, Inc. 2005. *See* page 31.

> 1983; Roll 1983), as well as the multiplicative nature of arithmetic returns (e.g., Levhari and Levy 1977; Longstaff 1989).[181]

This paper then adds "firm opacity" to the list of explanatory variables (i.e., the amount of time market participants require to understand the implications of systematic news on a company). The authors conclude:

> Our findings have several important implications. First, in the presence of opacity and risk-averse investors, high-frequency betas are not better or more precisely estimated proxies of systematic risk; instead they are distinct economic quantities relative to low frequency betas, which properly capture systematic risk. Specifically, our results show that unconditional as well as conditional market betas estimated from high-frequency returns are poor measures of risk.[182]

Thus, in summary, daily Betas are (a) poor measures of risk and (b) not comparable to weekly Betas.

For these reasons, Mr. Walters' CAPM results based on his average of outdated Value Line Betas (0.72) should be discarded as invalid, as should his results based on the S&P raw Betas that are calculated from daily returns (0.691).

Q. PLEASE SUMMARIZE MR. WALTERS' ASSUMPTIONS REGARDING THE MRP.

A. Mr. Walters provides three different estimates of the MRP, which I will refer to here as his MRP #1, #2, and #3.

For his MRP #1, Mr. Walters arithmetically combines a 93-year historical average of real annual S&P500 returns (9.0 percent) with an inflation expectation (2.0 percent) to generate an "expected" market return (11.2 percent). For his MRP #2, he inputs a published calculation of the current S&P500 dividend yield (1.68

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[181] Gilbert, Thomas & Hrdlicka, Christopher & Kalodimos, Jonathan & Siegel, Stephan. (2014). Daily Data is Bad for Beta: Opacity and Frequency-Dependent Betas. Review of Asset Pricing Studies. 4. 78-117. 10.1093/rapstu/rau001.

[182] *Ibid*.

percent) and projection of the S&P500 nominal earnings growth rate (11.51 percent) into a DCF model structure to generate an expected market return (13.38 percent). For his MRP #3, Mr. Walters modifies his MRP #2 by blending the S&P500 nominal earnings growth rate with a published projected long-term GDP growth rate (4.24 percent) to generate an expected market return (11.91 percent). For all three variations, he subtracts an estimated risk-free rate (1.80 percent) from his estimated market return to produce an estimated MRP. His resulting MRPs are 9.4 percent, 11.6 percent, and 10.1 percent, respectively.

Q. WHAT IS YOUR RESPONSE TO MR. WALTERS' FIRST MRP ESTIMATE?

A. I have four criticisms of Mr. Walters' MRP #1, which he estimates at 9.4 percent.

First, I do not agree with Mr. Walters' characterization of this MRP estimate as "forward-looking."[183] Rather, his estimate is in fact based on historical returns on the S&P 500.

Second, the Duff & Phelps data relied on by Mr. Walters to calculate his historical market return figure includes the negative returns from the financial market collapse of 2008. This is not reasonable, as Duff & Phelps explains:

> If one simply added an estimate of the ERP taken from commonly used sources before the Financial Crisis to the spot yield on 20-year U.S. government bonds at month-end December 2008, one would have arrived at an estimate of the cost of equity capital that was too low.
>
> For example, as illustrated in Exhibit 3.11, at December 2007 the yield on the 20-year U.S. government bonds equaled 4.5%, and the realized risk premium reported based on the average realized risk premiums for 1926-2007 was 7.1%. But at December 2008, the yield on 20-year U.S. government bonds was 3.0%, and the realized risk premium reported based on the average realized risk premiums for 1926-2008 was 6.5%. So just at the time that the risk in the

[183] *Id.*, at 44.

> economy increased to arguably the highest point, the base cost of equity capital using realized risk premiums decreased from 11.6% (4.5% plus 7.1%) to 9.5% (3.0% plus 6.5%).[184]

Third, Mr. Walters' use of *historical* market returns combined with a *current projected* risk-free rate ignores the fact that there exists an inverse relationship between interest rates and the equity risk premium: as interest rates decrease, the MRP increases. During each of the 93 years of historical market performance captured by Mr. Walters' average, a different interest rate was in effect, and thus a different equity premium was realized. When Mr. Walters now subtracts a *single* interest rate from an average of historical returns that represent a *wide range* of equity risk premia, he fails to account for the dynamic relationship between interest rates and equity risk premia. Due to the current low interest rate environment, this failure means that Mr. Walters' MRP #1 in the CAPM produces an underestimated ROE.

Lastly, as discussed previously, I disagree with the risk-free rate that Mr. Walters subtracts from his market return to produce his MRP #1 (and that he also uses in his CAPM equation to produce his ROE estimates).

Q. WHAT IS YOUR RESPONSE TO MR. WALTERS' SECOND MRP ESTIMATE?

A. Mr. Walters' MRP #2, which he estimates at 11.6 percent, uses the same methodological principle as I do to produce my MRP of 10.43 to 12.63 percent.[185] We arrive at slightly different MRP estimates for three reasons.

First, as summarized below in Figure 18 below, Mr. Walters and I reference different published sources to obtain assumptions about the current S&P 500 dividend yield and the projected S&P 500 earnings growth rate: Mr. Walters uses

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[184] Duff & Phelps, 2019 Valuation Handbook, U.S. Guide to Cost of Capital, Chapter 3, at 48.

[185] Direct Testimony of Christopher C. Walters, Attachment AEB-5RB and AEB-5.5RB.

State Street as his source, whereas I consider both Bloomberg data and the S&P Earnings and Estimates Report.

Second, as also reflected below in Figure 18, Mr. Walters uses a *less conservative* variant of the DCF equation than I do (i.e., his equation produces a higher market return output, given the same inputs). As I explain in my Direct Testimony,[186] I apply one-half of the expected annual dividend growth rate (g) when calculating the first-year dividend yield (D_0/ P_0). Mr. Walters does not:[187]

Bulkley: $k = (D_0*(1+0.5g))/P_0 + g$

Walters: $k = (D_0*(1+g))/P_0 + g$

Figure 18: Comparison of expected market returns used in Bulkley MRP versus Walters MRP #2

	State Street data used by Walters (as of 9/21/20)	Bloomberg data used by Bulkley (as of 9/30/20)	S&P Earnings and Estimates Report data used by Bulkley (as of 9/30/20)
Current weighted-average S&P500 dividend yield	1.68%	1.66%	1.68%
Projected weighted-average earnings growth rate of S&P500 (as a proxy for expected dividend growth rate)	11.51%	11.68%	12.27%
Expected market return, calculated using Walters' DCF formula	13.38%	n/a	n/a
Expected market return, calculated using Bulkley's DCF formula	13.29%	13.43%	14.05%

Lastly, as I discuss above in this Section of my response to Mr. Walters, I disagree with the risk-free rate that Mr. Walters subtracts from his market return to produce

[186] Direct Testimony of Ann E. Bulkley, at 40.
[187] Mr. Walters explains his method at 24, and shows it in equation form in footnotes, at 45 and 46.

his MRP #2 (and that he also uses in his CAPM equation to produce his ROE estimates).

Q. WHAT IS YOUR RESPONSE TO MR. WALTERS' THIRD MRP ESTIMATE?

A. I disagree with the methodology behind Mr. Walters' MRP #3, which he estimates at 10.1 percent. Mr. Walters characterizes his methodology as "a version of the FERC's two-step DCF methodology."[188] However, FERC in fact uses a single-step method to estimate market return.

Additionally, as discussed previously, I disagree with the risk-free rate that Mr. Walters subtracts from his market return to produce his MRP #3 (and that he also uses in his CAPM equation to produce his ROE estimates).

Q. HOW DO YOU RESPOND TO MR. WALTERS' CRITICISM OF THE MRP YOU RELY ON IN THE CAPM?

A. Mr. Walters spends several pages of his testimony contending that the long-term market growth rate used to calculate my MRPs is "far too high" to be sustainable[189] and is "economically and financially unfeasible."[190] (In my Direct Testimony, I had used the then-current Bloomberg projection of 11.84 percent. My updated calculations use the September 30, 2020, Bloomberg projection of 11.68 percent and S&P Earnings and Estimate Report projection of 12.27 percent.)

As discussed above and shown in Figure 18, Mr. Walters' own MRP #2 uses a long-term market growth rate of 11.51 percent, which differs from my own assumption merely due to which source of third-party published projections one favors. The fact that Mr. Walters criticizes my market growth rate assumption so

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188 Direct Testimony of Christopher C. Walters, at 46.
189 *Id.*, at 62.
190 *Id.*, at 64.

vigorously, while failing to consider his own, nearly identical market growth rate assumption through the same lens, discredits this entire portion of his testimony.

This inconsistency on the part of Mr. Walters arises again when he points out that all three of his expected market return estimates for his CAPM (composed of his current dividend yield and long-term market growth rate assumptions) vastly exceed analyst expectations.[191] While he seems entirely unbothered by the large gap he identifies between his market return expectations and those of analysts, later on in his testimony[192] he nonetheless takes great issue with my market growth rate and market return assumptions being too high.

Q. HOW DO YOU RESPOND TO MR. WALTERS' CRITICISM OF YOUR METHOD OF CALCULATING A MRP FOR YOUR CAPM?

A. As explained above, I use a DCF equation to calculate an implied market return from published estimates of the current S&P 500 dividend yield and projected S&P 500 earnings growth rate. Mr. Walters attempts to relate (a) this use of the constant growth DCF concept to solve for one unknown based on two variables, to (b) my use of DCF models to estimate an appropriate authorized ROE for APS.[193] In making this comparison, Mr. Walters is mistakenly conflating two different ideas.

As I explained in my Direct Testimony,[194] the reason why DCF models can understate required ROE is related to the effect that unusual market conditions can have on the input assumptions. And that is also the reason I have given as to why it is important to use projected data when possible. My cautionary comments about DCF results have no bearing on the DCF equation's arithmetic integrity and wide-ranging usefulness. Thus, it is illogical to attempt to impeach my ordinary use of a

[191] *Id.*, at 48.
[192] *Id.*, at 62-66.
[193] *Id.*, at 67.
[194] Direct Testimony of Ann E. Bulkley, at 34.

DCF equation for calculating the market return implied by certain metrics of market value.

To further clarify why an analyst might have "little faith"[195] in singular reliance on DCF models for estimating ROE, consider an example. When current dividend yields of the proxy group are abnormally low (as they are today), this has a more substantial impact on an ROE estimated using a DCF model than on an ROE estimated using the CAPM. As is illustrated in the mathematical expressions below, there are only two variables in the constant growth DCF equation used to estimate ROE: dividend yield and earnings growth rate; however, in the CAPM equation used to estimate ROE, there are four variables: dividend yield, earnings growth rate, risk-free rate, and Beta:

DCF: $ROE = V^*(1+0.5g) + g$

DCF: $r_m = V^*(1+0.5g) + g$

CAPM: $ROE = rf + B^*(r_m - rf)$

$= rf + B^*(V^*(1+0.5g) + g) - rf)$

As a result, in the CAPM, data problems and disputes with estimating any one variable are somewhat moderated by the presence of three other variables that also influence the result.

Q. IS IT RELEVANT FOR MR. WALTERS' TO COMPARE THE MRPS HE RELIES ON IN HIS CAPM TO A 93-YEAR HISTORICAL AVERAGE?

A. No. Mr. Walters compares the MRP estimates (9.4, 10.1, and 11.6 percent) used in his CAPM analysis to the difference between the average historical S&P500 return and average historical Treasury bond yield.[196] The MRP assumption in the CAPM should represent the expected MRP during the period that APS's rates will be in

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[195] Direct Testimony of Christopher C. Walters, at 67.

[196] *Id.*, at 47.

effect—not the MRP observed at prior points in history, or the average of varying MRPs achieved over a period as long as 93 years.

E. *Relevance of the Expected Earnings approach*

Q. PLEASE SUMMARIZE MR. WALTERS' OPINION REGARDING THE EXPECTED EARNINGS APPROACH TO ROE ESTIMATION.

A. Mr. Walters contends that my Expected Earnings analysis "should be rejected" because the approach measures the book accounting return and not "the market required return appropriate for the investment risk of APS."[197] He adds that "the earned return on book equity is simply not an accurate or legitimate basis upon which to determine a fair and reasonable return on equity for both investors and customers."[198] [199]

Q. WHAT IS YOUR RESPONSE TO MR. WALTERS' POSITION?

A. The Expected Earnings approach to ROE estimation provides an important, complementary perspective and serves as a "check" on the other ROE estimation approaches (DCF, Bond Yield Plus Risk Premium, and CAPM). In particular, the Expected Earnings approach is a good measure to verify the financial integrity of a proposed authorized ROE. More generally, the use of multiple methodologies has long been recognized as beneficial to the process of determining reasonable ROEs for regulated utilities. Notably, in the current proceeding, both Staff and RUCO have found it relevant to conduct a Comparable Earnings analysis.

In addition, the Expected Earnings approach is appealing in its relative simplicity. In contrast to the other ROE estimation approaches, it relies on just one

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[197] *Id.*, at 72.

[198] *Id.*, at 74.

[199] As a point of clarification, I must note that Mr. Walters repeatedly refers to the outcome of an Expected Earnings analysis as an "earned return on book equity", although it is in fact a projected return on book equity. An Expected Earnings analysis is not a post hoc evaluation of actual results, as Mr. Walters may be implying.

assumption—which is an uncontentious assumption by virtue of being a publicly available figure published by only one expert source.

Finally, I disagree with Mr. Walters regarding the methodological validity of the Expected Earnings approach. He argues that the Value Line projected ROEs refer to a return on book equity, which "cannot be used interchangeably"[200] with a market return on equity. However, despite this argument, Mr. Walters in fact uses the two measures interchangeably in his DCF approach to ROE estimation:

- In the first version of his Constant Growth DCF, Mr. Walters relies on published projections of the proxy companies' earnings growth rates (sourced from Zacks, Market Intelligence, and Yahoo! Finance).

- Meanwhile, in the second version of his Constant Growth DCF, Mr. Walters relies on published projections of the proxy companies' return on book equity (sourced from Value Line as projected earnings per share and projected book value per share, the quotient of which equals return on book equity).

Mr. Walters then proceeds to collectively consider the ROE results from all of his DCF model variants as defining a single range of reasonableness—without making any distinction as to whether they measure a market or book return or whether their inputs came from one data source or another. He refers to the second version of his Constant Growth DCF as a "sustainable growth DCF"; and he states explicitly that "the data used to estimate the long-term sustainable growth rate is based on the Company's current market-to-book ratio and on Value Line's three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances."[201] It is not clear how Mr. Walters comes to the opinion that the use of

[200] Direct Testimony of Christopher C. Walters, at 73.
[201] *Id.*, at 27.

Value Line ROE data is *not* reliable in my Expected Earnings analysis but *is* reliable in his DCF analysis.

F. *Model adjustments, characterization of model results, and relative merit of results from various ROE estimation approaches*

Q. MR. WALTERS PROPOSES CERTAIN CHANGES TO THE ROE ANALYSES PROVIDED IN YOUR DIRECT TESTIMONY.[202] WHAT IS YOUR RESPONSE TO HIS APPROACH TO THESE CHANGES?

A. The changes Mr. Walters makes, which he refers to as "corrections" and "adjustments" as well as "improvements,"[203] result in numbers that are unreasonably low as compared to authorized returns for vertically integrated electric utilities in recent years.

In addition, in his Table 12, Mr. Walters misleadingly presents his recommended ROE within a column entitled "Adjusted."[204] However, the 9.3 percent figure recommended by Mr. Walters' represents his own judgment of a final recommended ROE, based on his own analyses. Conceptually, it does not belong in his table of adjustments to my calculations.

Notably, though Mr. Walters recommends an ROE of 9.3 percent throughout his testimony, in the course of making "adjustments" to my calculations, he writes that the data supports an ROE of 9.2 percent.[205] This seems to be a residual number from some earlier version of Mr. Walters' work on this APS case—hinting at a lack of firmness in his final, subjective recommendation.

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[202] *Id.*, Table 12, at 58.
[203] *Id.*, at 58.
[204] *Id.*, Table 12, at 58.
[205] *Id.*, at 58.

Q. DO YOU AGREE WITH MR. WALTERS' PROPOSED CHANGES TO YOUR DCF ANALYSIS?

A. No, I do not. Mr. Walters does not in fact propose any changes to my DCF analysis. Instead, he simply selects different summary statistics from the results I had presented in my Direct Testimony attachments. Specifically, he uses the median and mean of my Constant Growth DCF model mean results to define the endpoints of an "adjusted" ROE range.[206] He calculates that median and mean using my raw results (prior to me having eliminated individual results lower than 7.00 percent), and he maintains that a median of raw results is preferable to using a mean of results from which low outliers have been eliminated.[207] Earlier in my response to Mr. Walters, I discussed the validity of eliminating low outliers.

Notably, although Mr. Walters criticizes my DCF analysis for using growth rates that he considers to be "excessive,"[208] he nevertheless does not propose any change to the growth rates I used.

Q. DO YOU AGREE WITH MR. WALTERS' PROPOSED CHANGES TO YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS?

A. No, I do not. Mr. Walters does not in fact propose any changes to my Bond Yield Plus Risk Premium analysis. Instead, he simply rearticulates his *own* Bond Yield Plus Risk Premium results (while misleadingly labelling that rearticulation as "Bulkley's adjusted" results).[209] I have previously addressed the flaws in Mr. Walters' own Bond Yield Plus Risk Premium results.

Additionally, Mr. Walters' Table 12 of adjusted results contains two errors regarding the Bond Yield Plus Risk Premium analysis. First, he presents his

[206] *Id.*, Table 12, at 58.
[207] *Id.*, at 59-60.
[208] *Id.*, at 59.
[209] *Id.*, Table 12, at 58.

"adjusted" ROE of 8.9 percent as the sum of his 7.02 percent historical utility equity risk premium and a short-term projected Treasury bond yield of 1.9 percent.[210] Meanwhile, elsewhere in his testimony he presents his ROE of 8.8 percent as the sum of his 7.02 percent historical utility equity risk premium and a short-term projected Treasury bond yield of 1.8 percent.[211] Either way, his use of a short-term projected Treasury bond yield of 1.8 or 1.9 percent would produce an *upward* adjustment to my Bond Yield Plus Risk Premium analysis (wherein I use a short-term projected Treasury bond yield of only 1.64 percent). Secondly, Mr. Walters presents his figure of 8.9 percent as an "adjustment" to my Bond Yield Plus Risk Premium results that are based on a current Treasury bond yield.[212] However, he does not in fact make any adjustment to my Bond Yield Plus Risk Premium results that are based on a current Treasury bond yield—rather, he simply rejects the use of a current Treasury bond yield altogether. If he had made such an adjustment, he certainly could not arrive at 8.9 percent by adjusting my results using his 1.37 percent current Treasury bond yield and also arrive at the same 8.9 percent answer by adjusting my results using his 1.8 (or 1.9) percent short-term projected Treasury bond yield.

Q. PLEASE COMMENT ON MR. WALTERS' PROPOSED CHANGES TO YOUR CAPM ANALYSIS.

A. Regarding my CAPM analysis, Mr. Walters changes only my expected market return.[213] He does not make any adjustment to my Betas or my current and near-term projected risk-free rate.

I do not agree with the expected market return of 12.16 percent which Mr. Walters substitutes for my market return. That figure is the average of three different

[210] *Id.*, at 58 and 72.
[211] *Id.*, at 40.
[212] *Id.*, Table 12, at 58.
[213] *Id.*, at 58.

expected market returns he produces—only one of which (13.38 percent) is calculated using the preferred method of a constant growth DCF equation.

In fact, Mr. Walters and I do not differ meaningfully regarding the expected market return as computed using a constant growth DCF equation. He arrives at 13.38 percent (using State Street's figures as of September 21, 2020), whereas I arrive at 13.43 percent (using Bloomberg's figures as of September 30, 2020) or 14.05 percent (using S&P's figures as of September 30. 2020), as discussed in my response to Mr. Walters.

Q. PLEASE RESPOND TO MR. WALTERS' OPINION THAT OBSERVABLE DATA IS BEST FOR DETERMINING THE FUTURE COST OF CAPITAL.

A. Mr. Walters makes the argument that "observable" data (as opposed to analyst projections) are best for determining future costs of capital (and thus the appropriate authorized ROE for a utility).[214] However, despite that stated position, Mr. Walters relies heavily on analyst projections to populate his own Constant Growth and Multi-Stage DCF models. Moreover, he bases his final ROE recommendation to a large extent on the results from those DCF models.

If Mr. Walters believes that observable data are indeed superior to projections, that belief should have led him to place more weight on his CAPM and Bond Yield Plus Risk Premium analysis, given that those approaches inherently rely on observed data (i.e., the observed, utility equity risk premium; and the observed, current Beta, which is calculated from recent years of historical data). And, placing more weight on the results from those modeling approaches would have led Mr. Walters to recommend a higher ROE in this proceeding than he has.

In fact, the widely accepted, best practice for estimating utilities' future cost of equity is to rely on a thoughtful combination of both observed and projected data.

[214] *Id.*, at 61.

Accordingly, it is important to consider—as I have done—multiple methodologies to estimate the cost of equity and a range of inputs to those ROE estimation models.

Q. WHAT IS YOUR RESPONSE TO MR. WALTERS' PROCESS OF USING HIS INDIVIDUAL MODEL RESULTS TO SUPPORT HIS FINAL ROE RECOMMENDATION?

A. Mr. Walters employs a two-step process to move from his raw modeling results to his recommended ROE figure. First, he summarizes the output range of each of his three types of ROE model (DCF, Bond Yield Plus Risk Premium, CAPM) with his judgment as to a single, representative ROE number. For example, he judges "9.6 percent" to represent his CAPM results that range from 8.31 to 12.16 percent (the calculated mean and median of which is actually 9.8 percent).[215] Second, he calculates the arithmetic mean of those three ROE judgments to obtain the ROE of 9.3 percent that he finally recommends.[216] Step one of Mr. Walters' process is *qualitative* and subjective. Step two of Mr. Walters' process presents as a *quantitative* calculation what is in fact a second layer of subjective judgment.

Q. DO YOU AGREE WITH THE METHOD BY WHICH MR. WALTERS' TESTS HIS RECOMMENDED ROE FOR REASONABLENESS?

A. No, I do not. To test the reasonableness of his recommended ROE, Mr. Walters calculates certain financial ratios that S&P uses to issue credit ratings.[217] Specifically, Mr. Walters calculates a hypothetical ratio of Funds From Operations (FFO) to Adjusted Debt and a hypothetical ratio of Adjusted Debt to EBITDA for APS, given his recommended 9.3 percent ROE. According to Mr. Walters' calculations, the resulting ratios correspond to an A rating by S&P.[218] Nonetheless, he asserts that his calculations support a bond rating of only A-.[219] This difference

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[215] *Id.*, at 51.
[216] *Id.*, at 52.
[217] *Id.*, at 52-56 and Attachment CCW-18DR.
[218] *Id.*, Attachment CCW-18DR.
[219] *Id.*, at 56.

suggests that Mr. Walters' is aware that his financial ratio test does not exactly replicate the complex method by which S&P assesses creditworthiness.

Q. PLEASE SUMMARIZE THE REASONABLE ADJUSTMENTS THAT CAN BE MADE TO MR. WALTERS' ROE ANALYSES TO PRODUCE RESULTS THAT ARE MORE COMPARABLE TO THE RETURNS ON OTHER INVESTMENTS OF SIMILAR RISK.

A. After making reasonable adjustments to the inputs used in Mr. Walters' DCF, Bond Yield Pus Risk Premium, and CAPM analyses, those approaches produce ROE results that are generally consistent with the authorized returns for other electric utilities in recent years. I propose the following specific changes to Mr. Walters' analyses (as shown in Exhibit AEB-11RB):

> 1) DCF: I propose modifying Mr. Walters' DCF analysis to rely only on the results from the version of his Constant Growth DCF model that uses analysts' projected earnings growth rates. This change shifts his range of mean DCF results to 9.47 to 9.50 percent (as compared to his original 8.64 to 9.50 percent range that he summarizes as 9.1 percent).
>
> 2) Bond Yield Plus Risk Premium: I disagree with Mr. Walters' Bond Yield Plus Risk Premium methodology. However, if the Commission were to rely on his methodology of simply adding a projected Treasury bond yield of 1.80 percent to a historical utility equity risk premium, then it would be more appropriate to rely on the most recent observation as opposed to the five-year historical average. Alternatively, I propose relying on Mr. Walters' projected Treasury bond yield of 1.80 percent in my regression equation to calculate a corresponding utility equity risk premium (and then adding his risk-free rate to that calculated value). These changes shift his range of Bond Yield Plus Risk Premium results to 9.45 to 9.64 percent (as compared to his original 8.50 to 9.20 percent range that he summarizes as 9.0 percent).
>
> 3) CAPM: I propose modifying Mr. Walters' CAPM analysis to rely only on the market return he computed via the constant growth DCF equation and to use only current adjusted Betas calculated using a weekly return interval (while keeping his risk-free rate assumption and proxy group definition intact). These

> changes shift his CAPM results to a single result of 12.16 percent (as compared to his original 8.31 to 12.16 percent range that he summarizes as 9.6 percent).

G. *Effect of APS's business risk on the Company's Cost of Equity*

Q. DO YOU AGREE WITH MR. WALTERS' ASSESSMENT OF THE COMPANY'S RISKINESS FOR INVESTORS?

A. No, I do not. Mr. Walters appears to conclude that APS is less risky than its proxy group, purely on the basis of relative credit ratings.[220] However, credit ratings are assessments of the likelihood a company could default on its *debt*; whereas, the topic of the current proceeding is to determine the riskiness and cost of the Company's *equity*. In my Direct Testimony, I explained that APS is *more* risky than its proxy group—not less. And I supported my argument with discussions about its relatively high regulatory risk,[221] its large capital investment program,[222] and its nuclear generation assets.[223]

Q. DO YOU AGREE WITH MR. WALTERS THAT ALL RISKS FACED BY THE COMPANY AND PROXY GROUP COMPANIES ARE ALREADY REFLECTED IN THEIR CREDIT RATINGS?

A. No, I do not. Mr. Walters dismisses the discussion of APS business risks in my Direct Testimony by claiming that all known risks are "taken into account" by rating agencies.[224] However, as I just explained above in this section, credit rating agencies evaluate a company's ability to pay *debt*—not *equity*. Equity and debt investors look at investment risk through different lenses. Some market conditions, managerial decisions, and operating environments can adversely affect a

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[220] Direct Testimony of Christopher C. Walters, at 22.
[221] Direct Testimony of Ann E. Bulkley, at 55.
[222] *Id.*, at 58
[223] *Id.*, at 59.
[224] Direct Testimony of Christopher C. Walters, at 75.

company's likelihood of paying dividends to equity holders without necessarily affecting that company's likelihood of paying interest due to debt holders.

Q. DO YOU AGREE WITH MR. WALTERS' OPINION THAT INVESTORS SHOULD ONLY GET COMPENSATED FOR MARKET RISK?

A. No, I do not. Mr. Walters recites an outdated characterization of "financial theory" as the notion that investors should only be compensated for "market risk" because they can diversify away company-specific risks.[225] It is true that the CAPM was developed to estimate the return required by equity investors to compensate for systematic (a/k/a "market") risk (as measured, theoretically, by Beta and the MRP), on the premise that unsystematic risk can hypothetically be diversified away in a large enough portfolio. However, financial theory also suggests it is appropriate to add a size premium and a company-specific risk premium to CAPM results.

Indeed, there can be many examples of risks that may affect a company going forward, but which have not previously occurred (or were previously perceived by investors as having a lower likelihood of ever occurring), and thus have not yet been fully priced into the company's valuation by investors—and therefore are not yet fully captured by the company's Beta.

One can also look to the policy and practice of FERC, which explicitly recognizes the need to compensate equity investors for company-specific risks. FERC has established that the "risk profile of a utility" should be used to determine where in the range of ROE results that particular utility's ROE should be set.[226] FERC has also observed "the CAPM's inability to fully account for the impact of firm size when determining the cost of equity" and determined that "size adjustments are

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[225] *Id.*, at 75.

[226] Opinion No. 569, 169 FERC ¶ 61,129 (November 21, 2019) at P 57. FERC reconfirmed its position on this matter in Opinion No. 569-A, 171 FERC ¶ 61,154 (May 21, 2020), for example at P 196: "risk profile is the particular circumstance most relevant to determining whether an existing ROE is unjust and unreasonable."

appropriate for the utility industry and improve the overall accuracy of the CAPM results."[227]

H. *Fair Value Increment Cost Rate*

Q. PLEASE SUMMARIZE MR. WALTERS' VERSUS YOUR RECOMMENDATION REGARDING THE FAIR VALUE INCREMENT.

A. Mr. Walters states that he disagrees with using a FVI, despite its basis in the Arizona Constitution and long history of application by the Commission.[228] He nonetheless offers a FVI cost rate recommendation, which he calculates as 0.65 percent (equal to 50 percent of his real risk-free rate estimate of 1.30 percent. He does not comment on the Company's Fair Value Rate Base (FVRB); he implicitly accepts the Company's proposed FVRB, by virtue of using it to calculate the resulting FVROR.

Based on market data as of August 2019, my recommended FVI cost rate was 0.81 percent (equal to 50 percent of the average real risk-free rate estimate of 1.62 percent).[229] Upon updating with current data, my recommendation is a FVI cost rate of 1.28 percent, equal to my estimate of the real risk-free rate, as shown below in Figure 19 and in Exhibit AEB-8RB.

[227] Opinion No. 569-A, 171 FERC ¶ 61,154 (May 21, 2020), at P 75. This opinion reconfirmed the FERC's position on this matter in Opinion No. 531-B (March 3, 2015).
[228] Direct Testimony of Christopher C. Walters, at 83.
[229] These figures reflect a corrected calculation as provided in Bulkley response to FEA 5.3.

Figure 19: Bulkley FVI cost rate recommendation

(Updated with current market data)

	Scenario 1	Scenario 2	Scenario 3
Nominal risk-free rate	3.40% [1]	3.40% [1]	2.50% [2]
Inflation	2.29% [3]	1.57% [4]	1.57% [4]
Real risk-free rate [5]	1.09%	1.83%	0.93%
Recommended FVI cost rate [6]		1.28%	

[1] Average of 5-year and 10-year projected 30-year T-bond yield, per Blue Chip, as of 6/1/20
[2] Duff & Phelps normalized nominal risk-free rate, as of 6/30/20
[3] Average of three forecasts, as shown in Exhibit AEB-8RB
[4] Equal to the average 30-year T-bond yield for the 180-day period ending 9/30/20, less the average TIPS yield for the 180-day period ending 9/30/20
[5] Equal to the nominal risk-free rate less inflation
[6] Equal to the mean of the three scenarios

The Company is requesting a FVI cost rate of 0.80 percent, which is conservative. Combined with my recommended ROE of 10.00 percent, a FVI cost rate of 0.80 percent produces a FVROR of 5.51 percent, as shown in Exhibit AEB-9RB.

I. *Equity ratio*

Q. WHAT IS YOUR RESPONSE TO MR. WALTERS' ASSESSMENT OF THE COMPANY'S PROPOSED EQUITY RATIO?

A. Mr. Walters believes the Company's proposed common equity ratio of 54.67 percent to be high.[230] While he does not go on to recommend an alternate ratio in his testimony, he does argue that the allegedly-high equity ratio can be used to justify recommending an ROE from the lower end of his range of model results.

I do not agree with Mr. Walters' perspective. Mr. Walters' opinion on this matter is based on his review of parent- and holding company-level equity ratios for the proxy group[231] and for the electric utility industry as a whole.[232] However, it is more appropriate to compare the Company's proposed common equity ratio to that of *other operating companies*—not to parent companies and holding companies.

[230] Direct Testimony of Christopher C. Walters, at 21.
[231] *Id.*, Attachment CCW-3DR.
[232] *Id.*, Table 2, at 6.

As I discuss in my Direct Testimony, the Company's proposed equity ratio falls in the middle of the range of equity ratios for operating companies in its proxy group.[233] Moreover, it also warrants reiterating that APS's 2017 rate settlement provided for an equity ratio of 55.8 percent. Therefore, the currently proposed equity ratio of 54.67 percent should *not* be used as part of any *post hoc* judgment regarding selecting an ROE from within model result ranges.

IX. RESPONSE TO AECC WITNESS HIGGINS

Q. PLEASE BRIEFLY SUMMARIZE MR. HIGGINS' TESTIMONY AS IT RELATES TO THE COMPANY'S ROE.

A. Mr. Higgins does not recommend a specific ROE. Rather, he observes that the proposed recommendation exceeds the median authorized ROEs for integrated electric utilities nationwide for the 12 months ending June 30, 2020, which according to Mr. Higgins is 9.75 percent. Mr. Higgins also contends that even if APS's authorized ROE is set at the national median, APS's effective ROE would actually be somewhat higher due to the FVI.[234]

Q. WHAT IS YOUR RESPONSE TO MR. HIGGINS ON THOSE POINTS?

A. Mr. Higgins observes that the Company's requested ROE is higher than the median return authorized for integrated electric utilities by other regulatory commissions. However, according to Regulatory Research Associates authorized ROEs for integrated electric utilities in the 12-month period ending September 30, 2020 have ranged from 9.25 percent to 10.50 percent. The returns proposed by the Opposing ROE witnesses in this proceeding are well below the average or median authorized ROE for integrated electric utilities and toward the lower end of the range of authorized returns in recent months.

[233] Direct Testimony of Ann E. Bulkley, at 60.
[234] Direct Testimony of Kevin C. Higgins, at 32.

Furthermore, although authorized returns were trending down after the Great Recession of 2008-2009, returns have stabilized in recent years. Mr. Higgins correctly observes that the Commission approved the settlement agreement in August 2017 that included an authorized ROE of 10.00 percent for APS. This return was approximately 25 basis points higher than the nationwide average for integrated electric utilities in the preceding 12 months. As discussed previously in my Rebuttal Testimony, APS has higher operating risk due to its ownership of nuclear generation assets than the utilities in other jurisdictions with a rate decision in the past year. Therefore, there is no basis to conclude that the Commission should now grant an authorized ROE for APS that is substantially below the national median of 9.75 percent over the past 12 months.

Lastly, I will address Mr. Higgins' assertion that APS's effective ROE would be somewhat higher than the national average due to the FVI. The FVI does not offset the low ROE that the other Opposing ROE witnesses have proposed in this proceeding. Even with the addition of a FVI, those ROEs are low, compared to the average of recently authorized ROEs for integrated electric utility companies, and also taking into consideration the business and regulatory risks that APS faces relative to those other companies.

X. <u>CONCLUSIONS AND RECOMMENDATION</u>

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE APPROPRIATE ROE FOR APS.

A. As discussed in Section IV of my Rebuttal Testimony, I have updated my analytical results based on market data as of September 30, 2020. Based on these updated results, I recognize that the short-term results of the analytical models have declined to some degree since the filing of my Direct Testimony. While interest rates on government and utility bonds have decreased in 2020, I believe that current market conditions are driven by short-term events. Over the longer term, investors continue to expect higher interest rates on government and corporate bonds. In addition, since mid-February 2020, equity markets have been characterized by uncertainty and volatility, as demonstrated by indicators such as elevated volatility in stock prices and substantial increases in Beta coefficients for regulated utilities. These factors suggest that, while interest rates have declined, the cost of equity has *increased*. Therefore, while some of the ROE estimation approaches are currently supporting an ROE lower than 10.15 percent for APS, I believe that without the market disruptions that have occurred in the last several months (which are discussed in Section V of my Rebuttal Testimony), the ROE would have remained in the range outlined in my Direct Testimony. Nonetheless, my updated range of results is 9.75 percent to 10.25 percent, and within that range the Company has elected to request a return of 10.00 percent—which, as I stated previously, is conservative, considering the risk factors for APS. While the analytical results of ROE estimation models provide a starting point in establishing a just and reasonable ROE, it is also important to consider other factors, including Company-specific risks, capital market conditions, and the capital attraction and comparable return standards. ROEs at the levels proposed by the Opposing ROE witnesses are not reasonable and do not meet the standards established in *Hope* and *Bluefield* for a fair return.

Q. WHAT IS YOUR RECOMMENDATION FOR THE FVROR FOR APS?

A. Based on the Company's requested ROE of 10.00 percent and requested FVI cost rate of 0.80 percent, a FVROR of 5.51 percent is reasonable and appropriate for APS, as shown in Exhibit AEB-9RB.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

30-DAY CONSTANT GROWTH DCF -- ARIZONA PUBLIC SERVICE COMPANY PROXY GROUP

											All Proxy Group			With Exclusions	
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.47	$52.86	4.67%	4.81%	4.50%	7.00%	NA%	5.75%	9.28%	10.56%	11.84%	9.28%	10.56%	11.84%
Ameren Corporation	AEE	$1.98	$78.39	2.53%	2.61%	6.00%	6.00%	6.90%	6.30%	8.60%	8.91%	9.51%	8.60%	8.91%	9.51%
American Electric Power Company, Inc.	AEP	$2.80	$79.66	3.51%	3.62%	6.00%	5.63%	5.60%	5.74%	9.21%	9.36%	9.62%	9.21%	9.36%	9.62%
DTE Energy Company	DTE	$4.05	$116.56	3.47%	3.58%	6.00%	5.95%	5.70%	5.88%	9.27%	9.46%	9.58%	9.27%	9.46%	9.58%
Duke Energy Corporation	DUK	$3.86	$82.07	4.70%	4.79%	5.00%	1.60%	4.30%	3.63%	6.34%	8.42%	9.82%		8.42%	9.82%
Exelon Corporation	EXC	$1.53	$36.25	4.22%	4.32%	5.00%	Negative	4.00%	4.50%	8.30%	8.82%	9.33%	8.30%	8.82%	9.33%
FirstEnergy Corporation	FE	$1.56	$28.73	5.43%	5.66%	8.50%	Negative	NA%	8.50%	14.16%	14.16%	14.16%	14.16%	14.16%	14.16%
Evergy, Inc.	EVRG	$2.02	$51.49	3.92%	4.04%	4.50%	6.80%	6.40%	5.90%	8.51%	9.94%	10.86%	8.51%	9.94%	10.86%
OGE Energy Corporation	OGE	$1.55	$30.63	5.06%	5.14%	3.00%	2.40%	3.70%	3.03%	7.52%	8.17%	8.85%	7.52%	8.17%	8.85%
Otter Tail Corporation	OTTR	$1.48	$37.66	3.93%	4.07%	5.00%	9.00%	NA%	7.00%	9.03%	11.07%	13.11%	9.03%	11.07%	13.11%
PNM Resources, Inc.	PNM	$1.23	$42.03	2.93%	3.00%	6.00%	4.95%	4.90%	5.28%	7.90%	8.29%	9.01%	7.90%	8.29%	9.01%
PPL Corporation	PPL	$1.66	$27.48	6.04%	6.12%	2.50%	Negative	NA%	2.50%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%
Southern Company	SO	$2.56	$52.77	4.85%	4.94%	3.00%	4.55%	4.00%	3.85%	7.92%	8.79%	9.51%	7.92%	8.79%	9.51%
Xcel Energy Inc.	XEL	$1.72	$68.96	2.49%	2.57%	6.00%	5.85%	5.80%	5.88%	8.37%	8.45%	8.57%	8.37%	8.45%	8.57%
Mean										8.79%	9.50%	10.17%	8.98%	9.50%	10.17%
Mean excluding FE, PPL										8.36%	9.19%	9.97%	8.54%	9.19%	9.97%
Mean excluding FE, PPL, DTE, SO										8.31%	9.20%	10.05%	**8.52%**	**9.20%**	**10.05%**

Notes:

[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of September 30, 2020.
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line (September 11, 2020; August 14, 2020; and July 24, 2020)
[6] Source: Yahoo! Finance, September 30, 2020
[7] Source: Zacks, September 30, 2020
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])
[12] - [14] Excludes companies with ROEs less than the a 7.00% return.

90-DAY CONSTANT GROWTH DCF -- ARIZONA PUBLIC SERVICE COMPANY PROXY GROUP

										All Proxy Group			With Exclusions		
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.47	$56.28	4.39%	4.51%	4.50%	7.00%	NA%	5.75%	8.99%	10.26%	11.54%	8.99%	10.26%	11.54%
Ameren Corporation	AEE	$1.98	$76.72	2.58%	2.66%	6.00%	6.00%	6.90%	6.30%	8.66%	8.96%	9.57%	8.66%	8.96%	9.57%
American Electric Power Company, Inc.	AEP	$2.80	$82.46	3.40%	3.49%	6.00%	5.63%	5.60%	5.74%	9.09%	9.24%	9.50%	9.09%	9.24%	9.50%
DTE Energy Company	DTE	$4.05	$112.92	3.59%	3.69%	6.00%	5.95%	5.70%	5.88%	9.39%	9.58%	9.69%	9.39%	9.58%	9.69%
Duke Energy Corporation	DUK	$3.86	$83.26	4.64%	4.72%	5.00%	1.60%	4.30%	3.63%	6.27%	8.35%	9.75%		8.35%	9.75%
Exelon Corporation	EXC	$1.53	$37.46	4.08%	4.18%	5.00%	Negative	4.00%	4.50%	8.17%	8.68%	9.19%	8.17%	8.68%	9.19%
FirstEnergy Corporation	FE	$1.56	$34.09	4.58%	4.77%	8.50%	Negative	NA%	8.50%	13.27%	13.27%	13.27%	13.27%	13.27%	13.27%
Evergy, Inc.	EVRG	$2.02	$57.38	3.52%	3.62%	4.50%	6.80%	6.40%	5.90%	8.10%	9.52%	10.44%	8.10%	9.52%	10.44%
OGE Energy Corporation	OGE	$1.55	$31.48	4.92%	5.00%	3.00%	2.40%	3.70%	3.03%	7.38%	8.03%	8.71%	7.38%	8.03%	8.71%
Otter Tail Corporation	OTTR	$1.48	$39.11	3.78%	3.92%	5.00%	9.00%	NA%	7.00%	8.88%	10.92%	12.95%	8.88%	10.92%	12.95%
PNM Resources, Inc.	PNM	$1.23	$41.08	2.99%	3.07%	6.00%	4.95%	4.90%	5.28%	7.97%	8.36%	9.08%	7.97%	8.36%	9.08%
PPL Corporation	PPL	$1.66	$27.05	6.14%	6.21%	2.50%	Negative	NA%	2.50%	8.71%	8.71%	8.71%	8.71%	8.71%	8.71%
Southern Company	SO	$2.56	$54.11	4.73%	4.82%	3.00%	4.55%	4.00%	3.85%	7.80%	8.67%	9.39%	7.80%	8.67%	9.39%
Xcel Energy Inc.	XEL	$1.72	$67.10	2.56%	2.64%	6.00%	5.85%	5.80%	5.88%	8.44%	8.52%	8.64%	8.44%	8.52%	8.64%
Mean										8.65%	9.36%	10.03%	8.83%	9.36%	10.03%
Mean excluding FE, PPL										8.63%	9.29%	9.92%	8.82%	9.29%	9.92%
Mean excluding FE, PPL, DTE, SO										8.19%	9.08%	9.94%	**8.41%**	**9.08%**	**9.94%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of September 30, 2020.
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line (September 11, 2020; August 14, 2020; and July 24, 2020)
[6] Source: Yahoo! Finance, September 30, 2020
[7] Source: Zacks, September 30, 2020
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])
[12] - [14] Excludes companies with ROEs less than the a 7.00% return.

180-DAY CONSTANT GROWTH DCF – ARIZONA PUBLIC SERVICE COMPANY PROXY GROUP

										All Proxy Group			With Exclusions		
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.47	$61.67	4.00%	4.12%	4.50%	7.00%	NA%	5.75%	8.60%	9.87%	11.15%	8.60%	9.87%	11.15%
Ameren Corporation	AEE	$1.98	$76.75	2.58%	2.66%	6.00%	6.00%	6.90%	6.30%	8.66%	8.96%	9.57%	8.66%	8.96%	9.57%
American Electric Power Company, Inc.	AEP	$2.80	$85.73	3.27%	3.36%	6.00%	5.63%	5.60%	5.74%	8.96%	9.10%	9.36%	8.96%	9.10%	9.36%
DTE Energy Company	DTE	$4.05	$111.83	3.62%	3.73%	6.00%	5.95%	5.70%	5.88%	9.42%	9.61%	9.73%	9.42%	9.61%	9.73%
Duke Energy Corporation	DUK	$3.86	$85.99	4.49%	4.57%	5.00%	1.60%	4.30%	3.63%	6.13%	8.20%	9.60%		8.20%	9.60%
Exelon Corporation	EXC	$1.53	$39.14	3.91%	4.00%	5.00%	Negative	4.00%	4.50%	7.99%	8.50%	9.01%	7.99%	8.50%	9.01%
FirstEnergy Corporation	FE	$1.56	$39.24	3.98%	4.14%	8.50%	Negative	NA%	8.50%	12.64%	12.64%	12.64%	12.64%	12.64%	12.64%
Evergy, Inc.	EVRG	$2.02	$60.04	3.36%	3.46%	4.50%	6.80%	6.40%	5.90%	7.94%	9.36%	10.28%	7.94%	9.36%	10.28%
OGE Energy Corporation	OGE	$1.55	$33.73	4.60%	4.67%	3.00%	2.40%	3.70%	3.03%	7.05%	7.70%	8.38%	7.05%	7.70%	8.38%
Otter Tail Corporation	OTTR	$1.48	$42.99	3.44%	3.56%	5.00%	9.00%	NA%	7.00%	8.53%	10.56%	12.60%	8.53%	10.56%	12.60%
PNM Resources, Inc.	PNM	$1.23	$43.02	2.86%	2.93%	6.00%	4.95%	4.90%	5.28%	7.83%	8.22%	8.94%	7.83%	8.22%	8.94%
PPL Corporation	PPL	$1.66	$28.02	5.92%	6.00%	2.50%	Negative	NA%	2.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%
Southern Company	SO	$2.56	$57.12	4.48%	4.57%	3.00%	4.55%	4.00%	3.85%	7.55%	8.42%	9.13%	7.55%	8.42%	9.13%
Xcel Energy Inc.	XEL	$1.72	$65.63	2.62%	2.70%	6.00%	5.85%	5.80%	5.88%	8.50%	8.58%	8.70%	8.50%	8.58%	8.70%
Mean										8.45%	9.16%	9.83%	8.63%	9.16%	9.83%
Mean excluding FE, PPL										8.44%	9.10%	9.73%	8.63%	9.10%	9.73%
Mean excluding FE, PPL, DTE, SO										8.02%	8.91%	9.76%	**8.23%**	**8.91%**	**9.76%**

Notes:

[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of September 30, 2020.
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line (September 11, 2020; August 14, 2020; and July 24, 2020)
[6] Source: Yahoo! Finance, September 30, 2020
[7] Source: Zacks, September 30, 2020
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])
[12] - [14] Excludes companies with ROEs less than the a 7.00% return.

PROJECTED CONSTANT GROWTH DCF -- ARIZONA PUBLIC SERVICE COMPANY PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
			Stock Price (2022-2024)											
Company	Ticker	Annualized Dividend	High	Low	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.47	$90.00	$65.00	$77.50	3.19%	3.28%	4.50%	7.00%	NA%	5.75%	7.76%	9.03%	10.30%
Ameren Corporation	AEE	$1.98	$85.00	$60.00	$72.50	2.73%	2.82%	6.00%	6.00%	6.90%	6.30%	8.81%	9.12%	9.73%
American Electric Power Company, Inc.	AEP	$2.80	$105.00	$85.00	$95.00	2.95%	3.03%	6.00%	5.63%	5.60%	5.74%	8.63%	8.78%	9.04%
DTE Energy Company	DTE	$4.05	$160.00	$120.00	$140.00	2.89%	2.98%	6.00%	5.95%	5.70%	5.88%	8.68%	8.86%	8.98%
Duke Energy Corporation	DUK	$3.86	$110.00	$80.00	$95.00	4.06%	4.14%	5.00%	1.60%	4.30%	3.63%	5.70%	7.77%	9.16%
Exelon Corporation	EXC	$1.53	$60.00	$40.00	$50.00	3.06%	3.13%	5.00%	Negative	4.00%	4.50%	7.12%	7.63%	8.14%
FirstEnergy Corporation	FE	$1.56	$60.00	$40.00	$50.00	3.12%	3.25%	8.50%	Negative	NA%	8.50%	11.75%	11.75%	11.75%
Evergy, Inc.	EVRG	$2.02	$80.00	$60.00	$70.00	2.89%	2.97%	4.50%	6.80%	6.40%	5.90%	7.45%	8.87%	9.78%
OGE Energy Corporation	OGE	$1.55	$55.00	$40.00	$47.50	3.26%	3.31%	3.00%	2.40%	3.70%	3.03%	5.70%	6.35%	7.02%
Otter Tail Corporation	OTTR	$1.48	$60.00	$45.00	$52.50	2.82%	2.92%	5.00%	9.00%	NA%	7.00%	7.89%	9.92%	11.95%
PNM Resources, Inc.	PNM	$1.23	$55.00	$35.00	$45.00	2.73%	2.81%	6.00%	4.95%	4.90%	5.28%	7.70%	8.09%	8.82%
PPL Corporation	PPL	$1.66	$45.00	$35.00	$40.00	4.15%	4.20%	2.50%	Negative	NA%	2.50%	6.70%	6.70%	6.70%
Southern Company	SO	$2.56	$70.00	$50.00	$60.00	4.27%	4.35%	3.00%	4.55%	4.00%	3.85%	7.33%	8.20%	8.91%
Xcel Energy Inc.	XEL	$1.72	$65.00	$55.00	$60.00	2.87%	2.95%	6.00%	5.85%	5.80%	5.88%	8.75%	8.83%	8.95%
Mean												7.86%	8.56%	9.23%
Mean excluding FE, PPL												7.63%	8.45%	9.23%
Mean excluding FE, PPL, DTE, SO												**7.55%**	**8.44%**	**9.29%**

Notes:
[1] Source: Value Line (September 11, 2020; August 14, 2020; and July 24, 2020)
[2] Source: Value Line (September 11, 2020; August 14, 2020; and July 24, 2020)
[3] Source: Value Line (September 11, 2020; August 14, 2020; and July 24, 2020)
[4] Source: Value Line (September 11, 2020; August 14, 2020; and July 24, 2020)
[5] Equals [1] / [4]
[6] Equals [5] x (1 + 0.50 x [10])
[7] Source: Value Line (September 11, 2020; August 14, 2020; and July 24, 2020)
[8] Source: Yahoo! Finance, September 30, 2020
[9] Source: Zacks, September 30, 2020
[10] Equals Average ([7], [8], [9])
[11] Equals [5] x (1 + 0.50 x Minimum ([7], [8], [9]) + Minimum ([7], [8], [9])
[12] Equals [6] + [10]
[13] Equals [5] x (1 + 0.50 x Maximum ([7], [8], [9]) + Maximum ([7], [8], [9])

BETA
As of September 30, 2020

		[1]	[2]
		Bloomberg	Value Line
ALLETE, Inc.	ALE	0.83	0.85
Ameren Corporation	AEE	0.76	0.80
American Electric Power Company, Inc.	AEP	0.76	0.75
DTE Energy Company	DTE	0.85	0.90
Duke Energy Corporation	DUK	0.72	0.85
Exelon Corporation	EXC	0.81	0.95
FirstEnergy Corporation	FE	0.80	0.85
Evergy, Inc.	EVRG	0.80	1.00
OGE Energy Corporation	OGE	0.93	1.05
Otter Tail Corporation	OTTR	0.87	0.85
PNM Resources, Inc.	PNM	0.94	0.90
PPL Corporation	PPL	0.92	1.10
Southern Company	SO	0.73	0.90
Xcel Energy Inc.	XEL	0.73	0.75
Mean		0.819	0.893
Mean excluding FE, PPL		0.813	0.879
Mean excluding FE, PPL, DTE, SO		**0.817**	**0.875**

Notes:
[1] Source: Bloomberg Professional, 10-year adjusted Beta
[2] Source: Value Line adjusted Beta (September 11, 2020; August 14, 2020; and July 24, 2(

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES
(Dividend Yield and Growth Rate sourced from Bloomberg)

[1] Estimated Weighted Average Dividend Yield	1.65%		
[2] Estimated Weighted Average Long-Term Growth Rate	11.68%		
[3] S&P 500 Estimated Required Market Return	13.43%		
[4] Risk-Free Rate	1.42%	1.64%	3.00%
[5] Implied Market Risk Premium	12.01%	11.79%	10.43%

	Name	Ticker	Shares Outst'g	Price	Current Dividend Yield	Bloomberg Long Term Growth	Market Cap	Market Cap. Excluding n/a Growth	% of Total Market Cap	Cap. Weighted Div. Yield	Cap. Weighted Long Term Growth
LYB UN Equity	LyondellBasell Industries N	LYB	333.8	69.25	6.06	6.75	23,118	23,118	0.08%	0.00%	0.01%
AXP UN Equity	American Express Co	AXP	805.2	100.32	1.72	4.33	80,774	80,774	0.28%	0.00%	0.01%
VZ UN Equity	Verizon Communications I	VZ	4,138.1	59.40	4.23	3.07	245,800	245,800	0.85%	0.04%	0.03%
AVGO UW Equity	Broadcom Inc	AVGO	404.5	366.47	3.55	9.82	148,238	148,238	0.51%	0.02%	0.05%
BA UN Equity	Boeing Co/The	BA	564.4	166.20	n/a	n/a	94,940	-	0.00%	n/a	n/a
CAT UN Equity	Caterpillar Inc	CAT	541.5	148.44	2.78	10.00	80,381	80,381	0.28%	0.01%	0.03%
JPM UN Equity	JPMorgan Chase & Co	JPM	3,047.6	96.81	3.72	5.40	295,039	295,039	1.02%	0.04%	0.06%
CVX UN Equity	Chevron Corp	CVX	1,867.3	70.87	7.28	-0.50	132,335	132,335	0.46%	0.03%	0.00%
KO UN Equity	Coca-Cola Co/The	KO	4,295.4	49.15	3.34	2.19	211,121	211,121	0.73%	0.02%	0.02%
ABBV UN Equity	AbbVie Inc	ABBV	1,764.8	87.36	5.41	2.05	154,176	154,176	0.53%	0.03%	0.01%
DIS UN Equity	Walt Disney Co/The	DIS	1,807.1	123.86	n/a	5.30	223,823	223,823	0.78%	n/a	0.04%
FLT UN Equity	FleetCor Technologies Inc	FLT	84.1	240.66	n/a	9.74	20,228	20,228	0.07%	n/a	0.01%
EXR UN Equity	Extra Space Storage Inc	EXR	129.1	109.35	3.29	3.10	14,114	14,114	0.05%	0.00%	0.00%
XOM UN Equity	Exxon Mobil Corp	XOM	4,228.2	33.24	10.47	6.21	140,546	140,546	0.49%	0.05%	0.03%
PSX UN Equity	Phillips 66	PSX	436.7	50.01	7.20	5.00	21,839	21,839	0.08%	0.01%	0.00%
GE UN Equity	General Electric Co	GE	8,753.3	6.16	0.65	5.53	53,876	53,876	0.19%	0.00%	0.01%
HPQ UN Equity	HP Inc	HPQ	1,373.5	19.10	3.69	5.19	26,234	26,234	0.09%	0.00%	0.00%
HD UN Equity	Home Depot Inc/The	HD	1,076.5	278.11	2.16	8.53	299,373	299,373	1.04%	0.02%	0.09%
IBM UN Equity	International Business Mac	IBM	890.6	121.80	5.35	1.43	108,472	108,472	0.38%	0.02%	0.01%
CXO UN Equity	Concho Resources Inc	CXO	196.7	43.06	1.86	14.20	8,470	8,470	0.03%	0.00%	0.00%
JNJ UN Equity	Johnson & Johnson	JNJ	2,632.8	148.27	2.72	5.40	390,389	390,389	1.35%	0.04%	0.07%
MCD UN Equity	McDonald's Corp	MCD	744.1	220.44	2.27	7.36	164,030	164,030	0.57%	0.01%	0.04%
MRK UN Equity	Merck & Co Inc	MRK	2,529.2	82.08	2.97	7.78	207,600	207,600	0.72%	0.02%	0.06%
MMM UN Equity	3M Co	MMM	576.0	159.80	3.68	7.05	92,048	92,048	0.32%	0.01%	0.02%
AWK UN Equity	American Water Works Co	AWK	181.2	146.82	1.50	8.00	26,604	26,604	0.09%	0.00%	0.01%
BAC UN Equity	Bank of America Corp	BAC	8,664.1	24.04	3.00	12.70	208,242	208,242	0.72%	0.02%	0.09%
BKR UN Equity	Baker Hughes Co	BKR	650.3	12.75	5.65	21.08	8,308	8,308	0.03%	0.00%	0.01%
PFE UN Equity	Pfizer Inc	PFE	5,556.9	36.39	4.18	5.00	202,187	202,187	0.70%	0.03%	0.04%
PG UN Equity	Procter & Gamble Co/The	PG	2,489.6	139.72	2.26	5.79	347,850	347,850	1.20%	0.03%	0.07%
T UN Equity	AT&T Inc	T	7,125.0	28.55	7.29	4.13	203,383	203,383	0.70%	0.05%	0.03%
TRV UN Equity	Travelers Cos Inc/The	TRV	484.7	8.39	0.95	11.82	4,067	4,067	0.01%	0.00%	0.00%
RTX UN Equity	Raytheon Technologies Co	RTX	253.2	107.87	3.15	9.84	27,310	27,310	0.09%	0.00%	0.01%
ADI UW Equity	Analog Devices Inc	ADI	1,527.7	57.87	3.28	n/a	88,405	-	0.00%	0.00%	n/a
WMT UN Equity	Walmart Inc	WMT	369.6	118.15	2.10	9.05	43,663	43,663	0.15%	0.00%	0.01%
CSCO UW Equity	Cisco Systems Inc	CSCO	2,833.8	143.11	1.51	5.10	405,538	405,538	1.40%	0.02%	0.07%
INTC UW Equity	Intel Corp	INTC	4,233.4	38.95	3.70	4.75	164,892	164,892	0.57%	0.02%	0.03%
GM UN Equity	General Motors Co	GM	4,253.0	52.32	2.52	6.62	222,517	222,517	0.77%	0.02%	0.05%
MSFT UW Equity	Microsoft Corp	MSFT	1,431.1	30.39	n/a	12.76	43,491	43,491	0.15%	n/a	0.02%
DG UN Equity	Dollar General Corp	DG	7,567.7	212.63	1.05	13.63	1,609,110	1,609,110	5.57%	0.06%	0.76%
CI UN Equity	Cigna Corp	CI	249.0	212.88	0.68	12.89	53,014	53,014	0.18%	0.00%	0.02%
KMI UN Equity	Kinder Morgan Inc	KMI	367.2	166.94	0.02	11.09	61,300	61,300	0.21%	0.00%	0.02%
C UN Equity	Citigroup Inc	C	2,263.5	12.21	8.60	6.35	27,638	27,638	0.10%	0.01%	0.01%
AIG UN Equity	American International Grc	AIG	2,081.9	42.84	4.76	3.17	89,187	89,187	0.31%	0.01%	0.01%
HON UN Equity	Honeywell International Inc	HON	861.4	27.64	4.63	13.57	23,810	23,810	0.08%	0.00%	0.01%
MO UN Equity	Altria Group Inc	MO	701.8	164.32	2.26	6.98	115,317	115,317	0.40%	0.01%	0.03%
HCA UN Equity	HCA Healthcare Inc	HCA	1,858.4	38.75	8.88	4.46	72,013	72,013	0.25%	0.02%	0.01%
UAA UN Equity	Under Armour Inc	UAA	338.0	122.60	n/a	10.08	41,443	41,443	0.14%	n/a	0.01%
IP UN Equity	International Paper Co	IP	188.5	11.54	n/a	n/a	2,176	-	0.00%	n/a	n/a
HPE UN Equity	Hewlett Packard Enterprise	HPE	393.1	40.35	5.08	3.15	15,861	15,861	0.05%	0.00%	0.00%
ABT UN Equity	Abbott Laboratories	ABT	1,286.4	9.32	5.15	0.78	11,989	11,989	0.04%	0.00%	0.00%
AFL UN Equity	Aflac Inc	AFL	1,770.5	109.57	1.31	8.39	193,997	193,997	0.67%	0.01%	0.06%
APD UN Equity	Air Products and Chemica	APD	712.9	36.36	3.08	n/a	25,921	-	0.00%	0.00%	n/a
RCL UN Equity	Royal Caribbean Cruises L	RCL	220.9	300.22	1.79	10.21	66,317	66,317	0.23%	0.00%	0.02%
HES UN Equity	Hess Corp	HES	214.7	64.16	n/a	-83.80	13,773	13,773	0.05%	n/a	-0.04%
ADM UN Equity	Archer-Daniels-Midland Co	ADM	307.1	39.19	2.55	27.45	12,007	12,007	0.04%	0.00%	0.01%
ADP UW Equity	Automatic Data Processing	ADP	555.6	46.40	3.10	7.20	25,782	25,782	0.09%	0.00%	0.01%
VRSK UW Equity	Verisk Analytics Inc	VRSK	429.8	138.74	2.62	12.00	59,637	59,637	0.21%	0.01%	0.02%
AZO UN Equity	AutoZone Inc	AZO	162.4	187.58	0.58	9.43	30,460	30,460	0.11%	0.00%	0.01%
AVY UN Equity	Avery Dennison Corp	AVY	23.4	1,178.00	n/a	7.92	27,517	27,517	0.10%	n/a	0.01%
MSCI UN Equity	MSCI Inc	MSCI	83.5	127.47	1.82	4.55	10,639	10,639	0.01%	0.00%	0.00%
BLL UN Equity	Ball Corp	BLL	83.6	361.61	0.66	11.75	30,244	30,244	0.10%	0.00%	0.01%
CARR UN Equity	Carrier Global Corp	CARR	326.5	84.18	0.71	6.07	27,490	27,490	0.10%	0.00%	0.01%
BK UN Equity	Bank of New York Mellon C	BK	866.2	30.84	1.04	5.10	26,713	26,713	0.09%	0.00%	0.00%
OTIS UN Equity	Otis Worldwide Corp	OTIS	885.9	34.03	3.64	4.83	30,141	30,141	0.10%	0.00%	0.01%
BAX UN Equity	Baxter International Inc	BAX	433.1	62.71	1.26	4.80	27,158	27,158	0.09%	0.00%	0.00%
BDX UN Equity	Becton Dickinson and Co	BDX	506.2	80.25	1.22	10.98	40,625	40,625	0.14%	0.00%	0.02%
BRK/B UN Equity	Berkshire Hathaway Inc	BRK/B	289.9	232.03	1.36	8.73	67,258	67,258	0.23%	0.00%	0.02%
BBY UN Equity	Best Buy Co Inc	BBY	1,401.4	212.83	n/a	-14.50	298,251	298,251	1.03%	n/a	-0.15%
BSX UN Equity	Boston Scientific Corp	BSX	258.8	113.49	1.04	8.26	29,375	29,375	0.10%	0.00%	0.01%

BMY UN Equity	Bristol-Myers Squibb Co	BMY	1,430.7	38.70	n/a	1.15	55,387	55 387	0.19%	n/a	0.00%
FBHS UN Equity	Fortune Brands Home & S	FBHS	2,253.9	59.99	3.00	10.85	135,214	135 214	0.47%	0.01%	0.05%
BF/B UN Equity	Brown-Forman Corp	BF/B	138.1	86.95	1.10	9.01	12,012	12 012	0.04%	0.00%	0.00%
COG UN Equity	Cabot Oil & Gas Corp	COG	309.4	75.34	0.93	3.02	23,307	23 307	0.08%	0.00%	0.00%
CPB UN Equity	Campbel Soup Co	CPB	398.6	17.06	2.34	9.05	6,800	6 800	0.02%	0.00%	0.00%
KSU UN Equity	Kansas City Southern	KSU	302.3	48.49	2.09	8.81	14,657	14 657	0.05%	0.00%	0.00%
HLT UN Equity	Hilton Worldwide Holdings	HLT	94.3	182.14	0.88	10.17	17,185	17 185	0.06%	0.00%	0.01%
CCL UN Equity	Carnival Corp	CCL	277.3	86.47	n/a	5.80	23,979	23 979	0.08%	n/a	0.00%
QRVO UW Equity	Qorvo Inc	QRVO	694.3	14.83	n/a	-29.71	10,293	10 293	0.04%	n/a	-0.01%
LUMN UN Equity	CenturyLink Inc	LUMN	114.2	133.08	n/a	13.14	15,203	15 203	0.05%	n/a	0.01%
UDR UN Equity	UDR Inc	UDR	1,097.5	10.00	10.00	-0.27	10,975	10 975	0.04%	0.00%	0.00%
CLX UN Equity	Clorox Co/The	CLX	295.1	33.16	4.34	4.02	9,784	9 784	0.03%	0.00%	0.00%
PAYC UN Equity	Paycom Software Inc	PAYC	126.0	211.67	2.10	6.06	26,666	26 666	0.09%	0.00%	0.01%
CMS UN Equity	CMS Energy Corp	CMS	58.5	317.45	n/a	21.20	18,581	18 581	0.06%	n/a	0.01%
NWL UW Equity	Newell Brands Inc	NWL	286.3	61.76	2.64	7.13	17,681	17 681	0.06%	0.00%	0.00%
CL UN Equity	Colgate-Palmolive Co	CL	424.3	17.02	5.41	-4.73	7,222	7 222	0.03%	0.00%	0.00%
CMA UN Equity	Comerica Inc	CMA	857.4	77.49	2.27	3.99	66,440	66 440	0.23%	0.01%	0.01%
IPGP UW Equity	IPG Photonics Corp	IPGP	139.0	38.07	7.14	14.75	5,293	5 293	0.02%	0.00%	0.00%
CAG UN Equity	Conagra Brands Inc	CAG	53.3	173.33	n/a	19.73	9,231	9 231	0.03%	n/a	0.01%
ED UN Equity	Consolidated Edison Inc	ED	488.5	35.49	3.10	7.30	17,336	17 336	0.06%	0.00%	0.00%
SLG UN Equity	SL Green Realty Corp	SLG	334.5	78.75	3.89	3.95	26,342	26 342	0.09%	0.00%	0.00%
GLW UN Equity	Corning Inc	GLW	73.3	46.32	7.64	6.15	3,393	3 393	0.01%	0.00%	0.00%
CMI UN Equity	Cummins Inc	CMI	761.3	32.39	2.72	7.20	24,674	24 674	0.09%	0.00%	0.01%
DHR UN Equity	Danaher Corp	DHR	147.7	206.91	2.51	3.92	30,651	30 651	0.11%	0.00%	0.00%
TGT UN Equity	Target Corp	TGT	709.4	215.70	0.33	10.86	153,019	153 019	0.53%	0.00%	0.06%
DE UN Equity	Deere & Co	DE	500.6	160.27	1.70	8.72	80,234	80 234	0.28%	0.00%	0.02%
D UN Equity	Dominion Energy Inc	D	313.4	221.73	1.37	6.18	69,485	69 485	0.24%	0.00%	0.01%
DOV UN Equity	Dover Corp	DOV	840.1	79.19	4.75	4.34	66,530	66 530	0.23%	0.01%	0.01%
LNT UW Equity	Alliant Energy Corp	LNT	144.0	107.79	1.83	10.83	15,519	15 519	0.05%	0.00%	0.01%
DUK UN Equity	Duke Energy Corp	DUK	249.6	52.19	2.91	5.75	13,029	13 029	0.05%	0.00%	0.00%
REG UW Equity	Regency Centers Corp	REG	735.4	89.48	4.31	3.98	65,806	65 806	0.23%	0.01%	0.01%
ETN UN Equity	Eaton Corp PLC	ETN	169.7	38.88	6.12	3.03	6,597	6 597	0.02%	0.00%	0.00%
ECL UN Equity	Ecolab Inc	ECL	400.1	101.22	2.88	10.03	40,498	40 498	0.14%	0.00%	0.01%
PKI UN Equity	PerkinElmer Inc	PKI	285.4	199.85	0.94	12.27	57,034	57 034	0.20%	0.00%	0.02%
EMR UN Equity	Emerson Electric Co	EMR	111.8	125.50	0.22	10.58	14,033	14 033	0.05%	0.00%	0.01%
EOG UN Equity	EOG Resources Inc	EOG	597.6	65.03	3.08	2.00	38,861	38 861	0.13%	0.00%	0.01%
AON UN Equity	Aon PLC	AON	582.2	34.87	4.30	2.33	20,303	20 303	0.07%	0.00%	0.00%
ETR UN Equity	Entergy Corp	ETR	231.7	205.51	0.66	10.00	47,606	47 606	0.16%	0.00%	0.02%
EFX UN Equity	Equifax Inc	EFX	200.2	99.64	3.73	8.11	19,949	19 949	0.07%	0.00%	0.00%
IQV UN Equity	IQVIA Holdings Inc	IQV	121.5	156.04	0.99	10.02	19,105	19 105	0.07%	0.00%	0.01%
IT UN Equity	Gartner Inc	IT	191.3	158.69	n/a	11.75	30,353	30 353	0.11%	n/a	0.01%
FDX UN Equity	FedEx Corp	FDX	89.2	125.46	n/a	12.50	11,195	11 195	0.04%	n/a	0.00%
FMC UN Equity	FMC Corp	FMC	262.6	256.21	1.01	13.60	67,279	67 279	0.23%	0.00%	0.03%
F UN Equity	Ford Motor Co	F	129.6	104.89	1.68	9.55	13,590	13 590	0.05%	0.00%	0.00%
NEE UN Equity	NextEra Energy Inc	NEE	3,907.5	6.73	n/a	12.74	26,298	26 298	0.09%	n/a	0.01%
BEN UN Equity	Franklin Resources Inc	BEN	489.6	281.84	1.99	8.52	138,002	138 002	0.48%	0.01%	0.04%
FCX UN Equity	Freeport-McMoRan Inc	FCX	495.4	20.01	5.40	2.89	9,912	9 912	0.03%	0.00%	0.00%
GPS UN Equity	Gap Inc/The	GPS	1,452.2	15.65	n/a	139.01	22,720	22 720	0.08%	n/a	0.11%
DXCM UW Equity	DexCom Inc	DXCM	373.5	17.55	5.53	4.10	6,553	6 553	0.02%	0.00%	0.00%
GD UN Equity	General Dynamics Corp	GD	95.7	412.44	n/a	32.12	39,486	39 486	0.14%	n/a	0.04%
GIS UN Equity	General Mills Inc	GIS	286.9	138.32	3.18	4.40	39,686	39 686	0.14%	0.00%	0.01%
GPC UN Equity	Genuine Parts Co	GPC	611.3	61.92	3.29	4.37	37,854	37 854	0.13%	0.00%	0.01%
ATO UN Equity	Atmos Energy Corp	ATO	144.3	95.40	3.31	1.96	13,763	13 763	0.05%	0.00%	0.00%
GWW UN Equity	WW Grainger Inc	GWW	123.4	95.81	2.40	7.34	11,819	11 819	0.04%	0.00%	0.00%
HAL UN Equity	Halliburton Co	HAL	53.5	358.16	1.71	9.85	19,187	19 187	0.07%	0.00%	0.01%
LHX UN Equity	L3Harris Technologies Inc	LHX	878.5	11.31	1.59	13.70	9,936	9 936	0.03%	0.00%	0.00%
PEAK UN Equity	Healthpeak Properties Inc	PEAK	216.2	174.45	1.95	17.84	37,715	37 715	0.13%	0.00%	0.02%
CTLT UN Equity	Catalent Inc	CTLT	538.3	27.52	5.58	-0.03	14,815	14 815	0.05%	0.00%	0.00%
FTV UN Equity	Fortive Corp	FTV	164.5	86.00	n/a	14.24	14,148	14 148	0.05%	n/a	0.01%
HSY UN Equity	Hershey Co/The	HSY	337.1	75.54	0.37	8.29	25,462	25 462	0.09%	0.00%	0.01%
SYF UN Equity	Synchrony Financial	SYF	147.4	143.43	2.24	7.40	21,143	21 143	0.07%	0.00%	0.01%
HRL UN Equity	Hormel Foods Corp	HRL	583.8	26.43	3.33	-6.66	15,429	15 429	0.05%	0.00%	0.00%
AJG UN Equity	Arthur J Gallagher & Co	AJG	539.5	49.10	1.89	3.75	26,495	26 495	0.09%	0.00%	0.00%
MDLZ UW Equity	Mondelez International Inc	MDLZ	191.5	105.99	1.70	9.21	20,294	20 294	0.07%	0.00%	0.01%
CNP UN Equity	CenterPoint Energy Inc	CNP	1,428.3	57.74	2.18	3.68	82,472	82 472	0.29%	0.01%	0.03%
HUM UN Equity	Humana Inc	HUM	544.6	19.33	3.10	1.01	10,529	10 529	0.04%	0.00%	0.00%
WLTW UW Equity	Willis Towers Watson PLC	WLTW	132.3	414.15	0.60	11.99	54,789	54 789	0.19%	0.00%	0.02%
ITW UN Equity	Illinois Tool Works Inc	ITW	128.9	209.10	1.30	10.00	26,944	26 944	0.09%	0.00%	0.01%
CDW UW Equity	CDW Corp/DE	CDW	316.2	192.10	2.37	6.30	60,735	60 735	0.21%	0.00%	0.01%
TT UN Equity	Trane Technologies PLC	TT	142.7	121.95	1.25	13.10	17,399	17 399	0.06%	0.00%	0.01%
IPG UN Equity	Interpublic Group of Cos Ir	IPG	239.4	122.31	1.73	4.65	29,275	29 275	0.10%	0.00%	0.00%
IFF UN Equity	International Flavors & Fra	IFF	389.9	16.77	6.08	0.02	6,539	6 539	0.02%	0.00%	0.00%
J UN Equity	Jacobs Engineering Group	J	106.9	122.82	2.51	7.20	13,133	13 133	0.05%	0.00%	0.00%
HBI UN Equity	Hanesbrands Inc	HBI	130.2	92.14	0.62	8.06	11,997	11 997	0.04%	0.00%	0.00%
K UN Equity	Kellogg Co	K	348.2	15.76	3.81	3.04	5,485	5 485	0.02%	0.00%	0.00%
BR UN Equity	Broadridge Financial Solut	BR	342.9	64.16	3.55	4.15	22,002	22 002	0.08%	0.00%	0.00%
PRGO UN Equity	Perrigo Co PLC	PRGO	115.2	134.40	1.71	7.40	15,478	15 478	0.05%	0.00%	0.00%
KMB UN Equity	Kimberly-Clark Corp	KMB	136.5	45.45	1.98	-3.60	6,203	6 203	0.02%	0.00%	0.00%
KIM UN Equity	Kimco Realty Corp	KIM	341.0	148.51	2.88	4.99	50,647	50 647	0.18%	0.01%	0.01%
ORCL UN Equity	Oracle Corp	ORCL	432.5	11.43	3.50	0.58	4,944	4 944	0.02%	0.00%	0.00%
KR UN Equity	Kroger Co/The	KR	3,010.9	59.95	1.60	2.84	180,503	180 503	0.63%	0.01%	0.06%
LEG UN Equity	Leggett & Platt Inc	LEG	774.3	34.06	2.11	8.02	26,374	26 374	0.09%	0.00%	0.01%
LEN UN Equity	Lennar Corp	LEN	132.4	41.70	3.84	8.00	5,521	5 521	0.02%	0.00%	0.00%
LLY UN Equity	Eli Lilly and Co	LLY	274.6	82.13	0.61	12.13	22,554	22 554	0.08%	0.00%	0.01%
LB UN Equity	L Brands Inc	LB	956.5	145.82	2.03	19.36	139,473	139 473	0.48%	0.01%	0.09%
CHTR UW Equity	Charter Communications I	CHTR	277.9	32.99	n/a	11.50	9,108	9 108	0.03%	n/a	0.00%
LNC UN Equity	Lincoln National Corp	LNC	204.9	633.41	n/a	40.95	129,785	129 785	0.45%	n/a	0.18%
L UN Equity	Loews Corp	L	193.2	31.78	5.03	9.00	6,141	6 141	0.02%	0.00%	0.00%
LOW UN Equity	Lowe's Cos Inc	LOW	280.4	34.86	0.72	n/a	9,776	-	0.00%	0.00%	n/a
HST UN Equity	Host Hotels & Resorts Inc	HST	755.7	167.51	1.43	16.98	126,593	126 593	0.44%	0.01%	0.07%
XRX UN Equity	Xerox Holdings Corp	XRX	705.3	10.91	n/a	5.00	7,694	7 694	0.03%	n/a	0.00%

IEX UN Equity	IDEX Corp	EX	212.8	18.72	5.34	1.00	3,984	3 984	0.01%	0.00%	0.00%
MMC UN Equity	Marsh & McLennan Cos Ir	MMC	75.5	180.98	1.11	11.58	13,666	13 666	0.05%	0.00%	0.01%
MAS UN Equity	Masco Corp	MAS	506.5	114.88	1.62	9.03	58,190	58 190	0.20%	0.00%	0.02%
SPGI UN Equity	S&P Global Inc	SPGI	261.5	55.52	1.01	11.04	14,520	14 520	0.05%	0.00%	0.01%
MDT UN Equity	Medtronic PLC	MDT	241.0	366.71	0.73	8.90	88,377	88 377	0.31%	0.00%	0.03%
CVS UN Equity	CVS Health Corp	CVS	1,344.2	103.43	2.24	7.54	139,032	139 032	0.49%	0.01%	0.04%
DD UN Equity	DuPont de Nemours Inc	DD	1,308.7	57.68	3.47	6.22	75,486	75 486	0.26%	0.01%	0.02%
MU UW Equity	Micron Technology Inc	MU	733.8	55.70	2.16	2.36	40,874	40 874	0.14%	0.00%	0.00%
MSI UN Equity	Motorola Solutions Inc	MSI	1,111.0	47.61	n/a	15.11	52,895	52 895	0.18%	n/a	0.03%
CBOE UF Equity	Cboe Global Markets Inc	CBOE	169.8	157.22	1.63	n/a	26,694	-	0.00%	0.00%	n/a
MYL UW Equity	Mylan NV	MYL	108.8	88.09	1.91	6.40	9,580	9 580	0.03%	0.00%	0.00%
LH UN Equity	Laboratory Corp of Americ	LH	516.9	14.90	n/a	1.69	7,703	7 703	0.03%	n/a	0.00%
NEM UN Equity	Newmont Corp	NEM	97.4	186.98	n/a	6.30	18,212	18 212	0.06%	n/a	0.00%
NKE UN Equity	NIKE Inc	NKE	803.1	63.78	1.57	11.05	51,220	51 220	0.18%	0.00%	0.02%
NI UN Equity	NiSource Inc	NI	1,244.9	126.43	0.78	24.69	157,389	157 389	0.55%	0.00%	0.13%
NSC UN Equity	Norfolk Southern Corp	NSC	383.0	22.01	3.62	5.74	8,430	8 430	0.03%	0.00%	0.00%
PFG UW Equity	Principal Financial Group I	PFG	255.1	213.95	1.76	6.13	54,581	54 581	0.19%	0.00%	0.01%
ES UN Equity	Eversource Energy	ES	274.5	40.35	5.55	6.55	11,077	11 077	0.04%	0.00%	0.00%
NOC UN Equity	Northrop Grumman Corp	NOC	342.7	84.81	2.68	6.97	29,062	29 062	0.10%	0.00%	0.01%
WFC UN Equity	Wells Fargo & Co	WFC	166.7	312.63	1.85	10.56	52,120	52 120	0.18%	0.00%	0.04%
NUE UN Equity	Nucor Corp	NUE	4,120.0	23.25	1.72	9.81	95,791	95 791	0.33%	0.01%	0.03%
PVH UN Equity	PVH Corp	PVH	301.9	45.13	3.56	4.90	13,625	13 625	0.05%	0.00%	0.00%
OXY UN Equity	Occidental Petroleum Corp	OXY	71.1	60.15	n/a	1.76	4,276	4 276	0.01%	n/a	0.00%
OMC UN Equity	Omnicom Group Inc	OMC	930.1	9.67	0.41	-1.00	8,994	8 994	0.03%	0.00%	0.00%
OKE UN Equity	ONEOK Inc	OKE	214.9	49.49	5.25	1.71	10,634	10 634	0.04%	0.00%	0.00%
RJF UN Equity	Raymond James Financial	RJF	444.2	25.62	14.60	2.49	11,380	11 380	0.04%	0.01%	0.00%
PH UN Equity	Parker-Hannifin Corp	PH	137.2	72.50	2.04	4.33	9,944	9 944	0.03%	0.00%	0.00%
ROL UN Equity	Rollins Inc	ROL	128.8	201.09	1.76	9.59	25,900	25 900	0.09%	0.00%	0.01%
PPL UN Equity	PPL Corp	PPL	327.8	54.13	0.59	n/a	17,742	-	0.00%	0.00%	n/a
COP UN Equity	ConocoPhillips	COP	768.8	27.56	8.03	0.45	21,188	21 188	0.07%	0.00%	0.00%
PHM UN Equity	PulteGroup Inc	PHM	1,072.6	32.23	5.21	-15.40	34,569	34 569	0.12%	0.01%	-0.02%
PNW UN Equity	Pinnacle West Capital Cor	PNW	268.2	46.61	1.03	10.19	12,500	12 500	0.04%	0.00%	0.00%
PNC UN Equity	PNC Financial Services Gr	PNC	112.6	75.18	4.16	4.58	8,462	8 462	0.03%	0.00%	0.00%
PPG UN Equity	PPG Industries Inc	PPG	424.5	100.41	4.20	-11.90	46,445	46 445	0.16%	0.01%	-0.02%
PGR UN Equity	Progressive Corp/The	PGR	236.0	123.09	1.75	8.18	29,045	29 045	0.10%	0.00%	0.01%
PEG UN Equity	Public Service Enterprise (	PEG	585.6	94.19	0.42	6.45	55,155	55 155	0.19%	0.00%	0.01%
RHI UN Equity	Robert Half International In	RHI	505.8	54.97	3.57	4.67	27,801	27 801	0.10%	0.00%	0.00%
EIX UN Equity	Edison International	EIX	114.6	52.67	2.58	6.57	6,038	6 038	0.02%	0.00%	0.00%
SLB UN Equity	Schlumberger NV	SLB	378.2	50.80	5.02	4.23	19,214	19 214	0.07%	0.00%	0.00%
SCHW UN Equity	Charles Schwab Corp/The	SCHW	1,388.1	15.17	3.30	35.60	21,051	21 051	0.07%	0.00%	0.03%
SHW UN Equity	Sherwin-Williams Co/The	SHW	1,288.6	37.26	1.93	1.20	48,008	48 008	0.17%	0.00%	0.00%
WST UN Equity	West Pharmaceutical Serv	WST	91.0	701.22	0.76	3.14	63,846	63 846	0.22%	0.00%	0.02%
SJM UN Equity	J M Smucker Co/The	SJM	73.8	277.26	0.23	14.94	20,473	20 473	0.07%	0.00%	0.01%
SNA UN Equity	Snap-on Inc	SNA	114.1	115.64	3.11	-0.13	13,191	13 191	0.05%	0.00%	0.00%
AME UN Equity	AMETEK Inc	AME	54.5	145.94	2.96	3.74	7,949	7 949	0.03%	0.00%	0.00%
SO UN Equity	Southern Co/The	SO	229.6	100.60	0.72	7.66	23,101	23 101	0.08%	0.00%	0.01%
TFC UN Equity	Truist Financial Corp	TFC	1,057.0	54.54	4.69	4.27	57,649	57 649	0.20%	0.01%	0.01%
LUV UN Equity	Southwest Airlines Co	LUV	1,347.6	38.18	4.71	2.17	51,452	51 452	0.18%	0.01%	0.00%
WRB UN Equity	W R Berkley Corp	WRB	589.9	37.97	n/a	4.00	22,397	22 397	0.08%	n/a	0.00%
SWK UN Equity	Stanley Black & Decker Inc	SWK	178.0	60.89	0.79	9.00	10,839	10 839	0.04%	0.00%	0.00%
PSA UN Equity	Public Storage	PSA	159.7	163.17	1.72	8.63	26,055	26 055	0.09%	0.00%	0.01%
ANET UN Equity	Arista Networks Inc	ANET	174.8	225.33	3.55	3.36	39,388	39 388	0.14%	0.00%	0.00%
SYY UN Equity	Sysco Corp	SYY	76.0	206.17	n/a	7.97	15,674	15 674	0.05%	n/a	0.00%
CTVA UN Equity	Corteva Inc	CTVA	508.5	62.75	2.67	10.15	31,911	31 911	0.11%	0.00%	0.01%
TXN UW Equity	Texas Instruments Inc	TXN	748.5	29.17	1.78	8.22	21,833	21 833	0.08%	0.00%	0.01%
TXT UN Equity	Textron Inc	TXT	915.9	144.96	2.81	10.00	132,775	132 775	0.46%	0.01%	0.05%
TMO UN Equity	Thermo Fisher Scientific In	TMO	228.0	35.49	0.23	5.98	8,093	8 093	0.03%	0.00%	0.00%
TIF UN Equity	Tiffany & Co	TIF	395.6	441.60	0.20	13.03	174,692	174 692	0.61%	0.00%	0.08%
TJX UN Equity	TJX Cos Inc/The	TJX	121.4	115.87	2.00	5.50	14,063	14 063	0.05%	0.00%	0.00%
GL UN Equity	Globe Life Inc	GL	1,199.1	57.20	n/a	10.00	68,586	68 586	0.24%	n/a	0.02%
JCI UN Equity	Johnson Controls Internati	JCI	106.5	79.99	0.94	n/a	8,520	-	0.00%	0.00%	n/a
ULTA UW Equity	Ulta Beauty Inc	ULTA	744.0	40.95	2.54	9.50	30,469	30 469	0.11%	0.00%	0.01%
UNP UN Equity	Union Pacific Corp	UNP	56.3	227.67	n/a	6.10	12,823	12 823	0.04%	n/a	0.00%
KEYS UN Equity	Keysight Technologies Inc	KEYS	678.8	195.87	1.98	7.43	132,964	132 964	0.46%	0.01%	0.03%
UNH UN Equity	UnitedHealth Group Inc	UNH	187.1	98.35	n/a	7.52	18,405	18 405	0.06%	n/a	0.00%
UNM UN Equity	Unum Group	UNM	950.3	312.06	1.60	12.32	296,562	296 562	1.03%	0.02%	0.13%
MRO UN Equity	Marathon Oil Corp	MRO	203.6	16.85	8.77	9.00	3,430	3 430	0.01%	0.00%	0.00%
VAR UN Equity	Varian Medical Systems In	VAR	789.4	3.96	n/a	0.90	3,126	3 126	0.01%	n/a	0.00%
BIO UN Equity	Bio-Rad Laboratories Inc	BIO	91.2	171.80	n/a	8.80	15,662	15 662	0.05%	n/a	0.00%
VTR UN Equity	Ventas Inc	VTR	24.6	518.47	n/a	21.75	12,747	12 747	0.04%	n/a	0.01%
VFC UN Equity	VF Corp	VFC	373.1	42.55	4.23	0.46	15,875	15 875	0.05%	0.00%	0.00%
VNO UN Equity	Vornado Realty Trust	VNO	389.6	70.81	2.71	8.70	27,591	27 591	0.10%	0.00%	0.01%
VMC UN Equity	Vulcan Materials Co	VMC	191.2	34.03	6.23	-4.73	6,505	6 505	0.02%	0.00%	0.00%
WY UN Equity	Weyerhaeuser Co	WY	132.4	135.36	1.00	15.52	17,928	17 928	0.06%	0.00%	0.01%
WHR UN Equity	Whirlpool Corp	WHR	746.3	28.40	n/a	54.40	21,194	21 194	0.07%	n/a	0.04%
WMB UN Equity	Williams Cos Inc/The	WMB	62.3	183.00	2.62	-0.42	11,400	11 400	0.04%	0.00%	0.00%
WEC UN Equity	WEC Energy Group Inc	WEC	1,213.5	19.04	8.41	9.70	23,100	23 100	0.08%	0.01%	0.01%
ADBE UW Equity	Adobe Inc	ADBE	315.4	97.86	2.59	6.47	30,868	30 868	0.11%	0.00%	0.01%
AES UN Equity	AES Corp/The	AES	479.7	498.82	n/a	16.45	239,291	239 291	0.83%	n/a	0.14%
AMGN UW Equity	Amgen Inc	AMGN	665.1	17.91	3.20	7.11	11,912	11 912	0.04%	0.00%	0.00%
AAPL UW Equity	Apple Inc	AAPL	585.7	255.72	2.50	7.67	149,774	149 774	0.52%	0.01%	0.04%
ADSK UW Equity	Autodesk Inc	ADSK	17,102.5	116.56	0.70	9.50	1,993,472	1 993 472	6.90%	0.05%	0.66%
CTAS UW Equity	Cintas Corp	CTAS	219.3	236.39	n/a	27.80	51,835	51 835	0.18%	n/a	0.05%
CMCSA UW Equity	Comcast Corp	CMCSA	104.6	341.66	0.75	9.86	35,722	35 722	0.12%	0.00%	0.01%
TAP UN Equity	Molson Coors Beverage C	TAP	4,558.7	46.33	1.99	10.65	211,203	211 203	0.73%	0.01%	0.08%
KLAC UW Equity	KLA Corp	KLAC	196.6	33.06	n/a	2.98	6,499	6 499	0.02%	n/a	0.00%
MAR UW Equity	Marriott International Inc/M	MAR	155.1	197.68	1.82	8.22	30,662	30 662	0.11%	0.00%	0.01%
MKC UN Equity	McCormick & Co Inc/MD	MKC	324.3	93.80	n/a	1.15	30,421	30 421	0.11%	n/a	0.00%
PCAR UW Equity	PACCAR Inc	PCAR	124.3	192.87	1.29	9.89	23,983	23 983	0.08%	0.00%	0.01%
COST UW Equity	Costco Wholesale Corp	COST	346.1	85.28	1.50	4.47	29,520	29 520	0.10%	0.00%	0.00%
FRC UN Equity	First Republic Bank/CA	FRC	441.3	358.86	0.78	9.08	158,349	158 349	0.55%	0.00%	0.05%

SYK UN Equity	Stryker Corp	SYK	171.3	109.88	0.73	7.85	18,821	18 821	0.07%	0.00%	0.01%
TSN UN Equity	Tyson Foods Inc	TSN	375.6	208.41	1.10	8.76	78,280	78 280	0.27%	0.00%	0.02%
LW UN Equity	Lamb Weston Holdings Inc	LW	294.3	59.24	2.84	4.08	17,431	17 431	0.06%	0.00%	0.00%
AMAT UW Equity	Applied Materials Inc	AMAT	145.3	66.94	1.37	11.40	9,727	9 727	0.03%	0.00%	0.00%
AAL UW Equity	American Airlines Group Ir	AAL	913.3	60.79	1.45	13.14	55,518	55 518	0.19%	0.00%	0.02%
CAH UN Equity	Cardinal Health Inc	CAH	508.5	12.55	n/a	-10.94	6,382	6 382	0.02%	n/a	0.00%
CERN UW Equity	Cerner Corp	CERN	293.4	46.34	4.19	1.90	13,596	13 596	0.05%	0.00%	0.00%
CINF UW Equity	Cincinnati Financial Corp	CINF	305.4	72.34	1.00	11.76	22,091	22 091	0.08%	0.00%	0.01%
VIAC UW Equity	ViacomCBS Inc	VIAC	160.9	77.41	3.10	n/a	12,452	-	0.00%	0.00%	n/a
DHI UN Equity	DR Horton Inc	DHI	563.8	27.34	3.51	0.06	15,414	15 414	0.05%	0.00%	0.00%
FLS UN Equity	Flowserve Corp	FLS	363.7	76.43	0.92	14.42	27,798	27 798	0.10%	0.00%	0.01%
EA UW Equity	Electronic Arts Inc	EA	130.2	26.58	3.01	2.08	3,460	3 460	0.01%	0.00%	0.00%
EXPD UW Equity	Expeditors International of	EXPD	288.8	132.67	n/a	6.48	38,315	38 315	0.13%	n/a	0.01%
FAST UW Equity	Fastenal Co	FAST	167.7	90.57	1.15	7.30	15,185	15 185	0.05%	0.00%	0.00%
MTB UN Equity	M&T Bank Corp	MTB	573.6	45.30	2.21	14.50	25,982	25 982	0.09%	0.00%	0.01%
XEL UW Equity	Xcel Energy Inc	XEL	128.3	91.45	4.61	-1.80	11,731	11 731	0.04%	0.00%	0.00%
FISV UW Equity	Fiserv Inc	FISV	525.3	70.15	2.45	3.94	36,853	36 853	0.13%	0.00%	0.01%
FITB UW Equity	Fifth Third Bancorp	FITB	669.7	104.16	n/a	17.09	69,751	69 751	0.24%	n/a	0.04%
GILD UW Equity	Gilead Sciences Inc	GILD	712.2	20.98	5.15	2.45	14,943	14 943	0.05%	0.00%	0.00%
HAS UW Equity	Hasbro Inc	HAS	1,253.7	62.97	4.32	2.20	78,047	78 047	0.27%	0.01%	0.02%
HBAN UW Equity	Huntington Bancshares Inc	HBAN	137.0	83.53	3.26	5.53	11,446	11 446	0.04%	0.00%	0.00%
WELL UN Equity	Welltower Inc	WELL	1,017.3	9.14	0.57	-2.84	9,293	9 293	0.03%	0.00%	0.00%
BIIB UW Equity	Biogen Inc	BIIB	417.3	55.23	4.41	3.14	23,048	23 048	0.08%	0.00%	0.00%
NTRS UW Equity	Northern Trust Corp	NTRS	158.3	281.79	n/a	1.55	44,611	44 611	0.15%	n/a	0.00%
PKG UN Equity	Packaging Corp of Americ	PKG	208.1	77.21	3.63	2.11	16,067	16 067	0.06%	0.00%	0.00%
PAYX UW Equity	Paychex Inc	PAYX	94.8	109.07	2.00	5.60	10,344	10 344	0.04%	0.00%	0.00%
PBCT UW Equity	People's United Financial I	PBCT	360.0	79.55	3.12	6.15	28,636	28 636	0.10%	0.00%	0.01%
QCOM UW Equity	QUALCOMM Inc	QCOM	424.8	10.22	7.05	2.00	4,341	4 341	0.02%	0.00%	0.00%
ROP UN Equity	Roper Technologies Inc	ROP	1,128.0	118.48	2.19	12.45	133,645	133 645	0.46%	0.01%	0.06%
ROST UW Equity	Ross Stores Inc	ROST	104.7	397.92	0.52	12.93	41,667	41 667	0.14%	0.00%	0.02%
IDXX UW Equity	IDEXX Laboratories Inc	IDXX	356.0	95.48	n/a	10.00	33,991	33 991	0.12%	n/a	0.01%
SBUX UW Equity	Starbucks Corp	SBUX	85.1	395.95	n/a	13.21	33,677	33 677	0.12%	n/a	0.02%
KEY UN Equity	KeyCorp	KEY	1,169.0	87.07	2.07	13.83	101,785	101 785	0.35%	0.01%	0.05%
FOXA UW Equity	Fox Corp	FOXA	976.0	11.88	6.23	4.80	11,595	11 595	0.04%	0.00%	0.00%
FOX UW Equity	Fox Corp	FOX	338.8	27.73	1.66	-0.10	9,395	9 395	0.03%	0.00%	0.00%
STT UN Equity	State Street Corp	STT	258.4	27.88	1.65	-0.10	7,204	7 204	0.02%	0.00%	0.00%
NCLH UN Equity	Norwegian Cruise Line Ho	NCLH	352.4	58.86	3.54	6.18	20,741	20 741	0.07%	0.00%	0.00%
USB UN Equity	US Bancorp	USB	275.6	16.90	n/a	-83.04	4,658	4 658	0.02%	n/a	-0.01%
AOS UN Equity	A O Smith Corp	AOS	1,506.4	35.79	4.69	3.30	53,913	53 913	0.19%	0.01%	0.01%
NLOK UW Equity	NortonLifeLock Inc	NLOK	135.4	53.91	1.78	n/a	7,298	-	0.00%	0.00%	n/a
TROW UW Equity	T Rowe Price Group Inc	TROW	591.0	20.80	2.40	8.03	12,293	12 293	0.04%	0.00%	0.00%
WM UN Equity	Waste Management Inc	WM	227.0	128.43	2.00	6.25	29,152	29 152	0.10%	0.00%	0.01%
STZ UN Equity	Constellation Brands Inc	STZ	422.5	112.82	1.93	5.59	47,662	47 662	0.17%	0.00%	0.01%
XLNX UW Equity	Xilinx Inc	XLNX	168.0	185.01	1.62	6.85	31,085	31 085	0.11%	0.00%	0.01%
XRAY UW Equity	DENTSPLY SIRONA Inc	XRAY	244.3	105.91	1.44	8.53	25,875	25 875	0.09%	0.00%	0.01%
ZION UW Equity	Zions Bancorp NA	ZION	218.5	43.23	0.93	5.80	9,446	9 446	0.03%	0.00%	0.00%
ALK UN Equity	Alaska Air Group Inc	ALK	164.0	28.99	4.69	3.26	4,754	4 754	0.02%	0.00%	0.00%
IVZ UN Equity	Invesco Ltd	IVZ	123.6	36.95	n/a	n/a	4,568	-	0.00%	n/a	n/a
LIN UN Equity	Linde PLC	LIN	459.2	11.27	5.50	-7.07	5,175	5 175	0.02%	0.00%	0.00%
INTU UW Equity	Intuit Inc	INTU	525.5	236.40	1.63	10.43	124,237	124 237	0.43%	0.01%	0.04%
MS UN Equity	Morgan Stanley	MS	261.8	331.90	0.71	13.44	86,894	86 894	0.30%	0.00%	0.04%
MCHP UW Equity	Microchip Technology Inc	MCHP	1,576.8	47.93	2.92	10.00	75,574	75 574	0.26%	0.01%	0.03%
CB UN Equity	Chubb Ltd	CB	252.5	106.25	1.39	13.33	26,823	26 823	0.09%	0.00%	0.01%
HOLX UW Equity	Hologic Inc	HOLX	451.4	116.59	2.68	9.37	52,625	52 625	0.18%	0.00%	0.02%
CFG UN Equity	Citizens Financial Group Ir	CFG	259.0	66.66	n/a	16.42	17,264	17 264	0.06%	n/a	0.01%
ORLY UW Equity	O'Reilly Automotive Inc	ORLY	426.8	25.35	6.15	-14.65	10,820	10 820	0.04%	0.00%	-0.01%
ALL UN Equity	Allstate Corp/The	ALL	74.1	464.56	n/a	10.58	34,408	34 408	0.12%	n/a	0.01%
FLIR UW Equity	FLIR Systems Inc	FLIR	312.3	93.35	2.32	9.00	29,155	29 155	0.10%	0.00%	0.01%
EQR UN Equity	Equity Residential	EQR	131.1	35.91	1.89	9.50	4,709	4 709	0.02%	0.00%	0.00%
BWA UN Equity	BorgWarner Inc	BWA	372.2	52.50	4.59	2.57	19,541	19 541	0.07%	0.00%	0.00%
INCY UW Equity	Incyte Corp	INCY	207.3	39.60	1.72	7.01	8,207	8 207	0.03%	0.00%	0.00%
SPG UN Equity	Simon Property Group Inc	SPG	218.7	91.54	n/a	30.05	20,020	20 020	0.07%	n/a	0.02%
EMN UN Equity	Eastman Chemical Co	EMN	305.9	65.39	7.95	0.60	20,002	20 002	0.07%	0.01%	0.00%
TWTR UN Equity	Twitter Inc	TWTR	135.3	77.14	3.42	2.92	10,441	10 441	0.04%	0.00%	0.00%
AVB UN Equity	AvalonBay Communities Ir	AVB	790.9	45.74	n/a	9.50	36,178	36 178	0.13%	n/a	0.01%
PRU UN Equity	Prudential Financial Inc	PRU	140.7	153.05	4.15	3.73	21,541	21 541	0.07%	0.00%	0.00%
UPS UN Equity	United Parcel Service Inc	UPS	395.0	63.62	6.92	9.00	25,130	25 130	0.09%	0.01%	0.01%
AIV UN Equity	Apartment Investment and	AIV	707.1	169.37	2.39	9.30	119,758	119 758	0.41%	0.01%	0.04%
WBA UW Equity	Walgreens Boots Alliance	WBA	148.9	34.44	4.76	-0.76	5,127	5 127	0.02%	0.00%	0.00%
STE UN Equity	STERIS PLC	STE	866.5	35.94	5.20	-1.11	31,143	31 143	0.11%	0.01%	0.00%
MCK UN Equity	McKesson Corp	MCK	85.1	175.50	0.91	-4.80	14,927	14 927	0.05%	0.00%	0.00%
LMT UN Equity	Lockheed Martin Corp	LMT	162.2	148.19	1.13	2.77	24,035	24 035	0.09%	0.00%	0.01%
ABC UN Equity	AmerisourceBergen Corp	ABC	279.5	385.10	2.70	7.32	107,652	107 652	0.37%	0.01%	0.03%
COF UN Equity	Capital One Financial Corp	COF	204.1	95.82	1.75	5.54	19,561	19 561	0.07%	0.00%	0.00%
WAT UN Equity	Waters Corp	WAT	456.6	72.36	0.55	1.65	33,042	33 042	0.11%	0.00%	0.00%
DLTR UW Equity	Dollar Tree Inc	DLTR	61.9	195.55	n/a	3.13	12,110	12 110	0.04%	n/a	0.00%
DRI UN Equity	Darden Restaurants Inc	DRI	237.3	92.44	n/a	9.10	21,937	21 937	0.08%	n/a	0.01%
DPZ UN Equity	Domino's Pizza Inc	DPZ	130.1	103.19	1.16	15.39	13,423	13 423	0.05%	0.00%	0.01%
NVR UN Equity	NVR Inc	NVR	39.3	427.01	0.73	15.89	16,802	16 802	0.06%	0.00%	0.01%
NTAP UW Equity	NetApp Inc	NTAP	3.7	4,145.66	n/a	7.92	15,349	15 349	0.05%	n/a	0.00%
CTXS UW Equity	Citrix Systems Inc	CTXS	222.0	43.32	4.43	7.75	9,617	9 617	0.03%	0.00%	0.00%
DXC UN Equity	DXC Technology Co	DXC	123.5	139.16	1.01	9.63	17,193	17 193	0.06%	0.00%	0.01%
ODFL UW Equity	Old Dominion Freight Line	ODFL	254.2	18.31	n/a	23.03	4,654	4 654	0.02%	n/a	0.00%
DVA UN Equity	DaVita Inc	DVA	117.3	184.11	0.33	9.24	21,602	21 602	0.07%	0.00%	0.01%
HIG UN Equity	Hartford Financial Services	HIG	122.0	81.64	n/a	11.17	9,960	9 960	0.03%	n/a	0.00%
IRM UN Equity	Iron Mountain Inc	IRM	350.2	36.90	3.52	9.50	13,240	13 240	0.05%	0.00%	0.00%
EL UN Equity	Estee Lauder Cos Inc/The	EL	288.1	26.87	9.21	0.06	7,743	7 743	0.03%	0.00%	0.00%
CDNS UW Equity	Cadence Design Systems	CDNS	226.1	220.05	0.67	14.99	49,762	49 762	0.17%	0.00%	0.03%
TYL UN Equity	Tyler Technologies Inc	TYL	278.8	108.54	n/a	10.89	30,260	30 260	0.10%	n/a	0.01%
UHS UN Equity	Universal Health Services I	UHS	40.2	354.55	n/a	13.25	14,267	14 267	0.05%	n/a	0.01%
SWKS UW Equity	Skyworks Solutions Inc	SWKS	77.7	104.90	n/a	8.00	8,151	8 151	0.03%	n/a	0.00%

NOV UN Equity	National Oilwell Varco Inc	NOV	221.1	49.99	1.12	-9.84	11,053	11 053	0.04%	0.00%	0.00%
DGX UN Equity	Quest Diagnostics Inc	DGX	167.0	146.80	1.34	13.80	24,655	24 655	0.09%	0.00%	0.01%
ATVI UW Equity	Activision Blizzard Inc	ATVI	388.3	8.70	n/a	19.15	3,378	3 378	0.01%	n/a	0.00%
ROK UN Equity	Rockwell Automation Inc	ROK	134.3	113.50	1.07	13.32	15,243	15 243	0.05%	0.00%	0.01%
KHC UW Equity	Kraft Heinz Co/The	KHC	771.9	82.87	0.49	16.19	63,965	63 965	0.22%	0.00%	0.04%
AMT UN Equity	American Tower Corp	AMT	116.0	221.37	1.04	7.44	25,072	25 072	0.09%	0.00%	0.01%
HFC UN Equity	HollyFrontier Corp	HFC	1,222.6	29.97	5.34	1.53	36,641	36 641	0.13%	0.01%	0.00%
REGN UW Equity	Regeneron Pharmaceutica	REGN	443.6	243.86	1.67	15.61	108,169	108 169	0.37%	0.01%	0.06%
AMZN UW Equity	Amazon.com Inc	AMZN	162.0	18.79	7.45	-3.06	3,044	3 044	0.01%	0.00%	0.00%
JKHY UW Equity	Jack Henry & Associates Ir	JKHY	104.5	555.90	n/a	9.58	58,116	58 116	0.20%	n/a	0.02%
RL UN Equity	Ralph Lauren Corp	RL	500.9	3,196.00	n/a	32.26	1,600,843	1,600 843	5.54%	n/a	1.79%
BXP UN Equity	Boston Properties Inc	BXP	76.6	164.72	1.04	10.47	12,624	12 624	0.04%	0.00%	0.00%
APH UN Equity	Amphenol Corp	APH	48.2	67.95	n/a	4.57	3,273	3 273	0.01%	n/a	0.00%
HWM UN Equity	Howmet Aerospace Inc	HWM	155.5	81.58	4.61	3.16	12,697	12 697	0.04%	0.00%	0.00%
PXD UN Equity	Pioneer Natural Resources	PXD	298.4	109.97	0.91	8.08	32,813	32 813	0.11%	0.00%	0.01%
VLO UN Equity	Valero Energy Corp	VLO	436.1	17.06	n/a	39.00	7,441	7 441	0.03%	n/a	0.01%
SNPS UW Equity	Synopsys Inc	SNPS	164.3	84.97	2.59	14.95	13,959	13 959	0.05%	0.00%	0.01%
WU UN Equity	Western Union Co/The	WU	407.8	39.79	9.65	1.34	16,225	16 225	0.06%	0.01%	0.00%
ETSY UW Equity	Etsy Inc	ETSY	151.8	217.03	n/a	14.03	32,937	32 937	0.11%	n/a	0.02%
CHRW UW Equity	CH Robinson Worldwide Ir	CHRW	411.0	21.26	4.23	-0.30	8,738	8 738	0.03%	0.00%	0.00%
ACN UN Equity	Accenture PLC	ACN	119.3	129.63	n/a	10.00	15,468	15 468	0.05%	n/a	0.01%
TDG UN Equity	TransDigm Group Inc	TDG	134.8	102.26	2.00	2.03	13,787	13 787	0.05%	0.00%	0.00%
YUM UN Equity	Yum! Brands Inc	YUM	636.2	226.49	1.55	10.40	144,092	144 092	0.50%	0.01%	0.05%
PLD UN Equity	Prologis Inc	PLD	54.2	479.93	n/a	4.03	26,015	26 015	0.09%	n/a	0.00%
FE UN Equity	FirstEnergy Corp	FE	301.4	91.90	2.05	11.38	27,696	27 689	0.10%	0.00%	0.01%
VRSN UW Equity	VeriSign Inc	VRSN	738.5	101.50	2.29	7.27	74,966	74 966	0.26%	0.01%	0.02%
PWR UN Equity	Quanta Services Inc	PWR	542.1	28.85	5.41	2.21	15,640	15 640	0.05%	0.00%	0.00%
HSIC UW Equity	Henry Schein Inc	HSIC	114.9	207.32	n/a	10.30	23,811	23 811	0.09%	n/a	0.01%
AEE UN Equity	Ameren Corp	AEE	138.8	53.16	0.38	11.00	7,381	7 381	0.03%	0.00%	0.00%
ANSS UW Equity	ANSYS Inc	ANSS	142.6	58.09	n/a	2.88	8,293	8 293	0.03%	n/a	0.00%
NVDA UW Equity	NVIDIA Corp	NVDA	246.7	79.73	2.48	7.09	19,672	19 672	0.07%	0.00%	0.00%
SEE UN Equity	Sealed Air Corp	SEE	85.8	332.42	n/a	10.90	28,518	28 518	0.10%	n/a	0.01%
CTSH UW Equity	Cognizant Technology Sol	CTSH	617.0	542.83	0.12	20.82	334,926	334 926	1.16%	0.00%	0.24%
SIVB UW Equity	SVB Financial Group	SIVB	155.7	39.62	1.62	4.22	6,168	6 168	0.02%	0.00%	0.00%
ISRG UW Equity	Intuitive Surgical Inc	ISRG	542.2	69.51	1.27	10.15	37,691	37 691	0.13%	0.00%	0.01%
TTWO UW Equity	Take-Two Interactive Softw	TTWO	51.8	243.19	n/a	10.00	12,588	12 588	0.04%	n/a	0.00%
RSG UN Equity	Republic Services Inc	RSG	117.0	710.91	n/a	7.88	83,195	83 195	0.29%	n/a	0.02%
EBAY UW Equity	eBay Inc	EBAY	114.3	167.00	n/a	8.84	19,095	19 095	0.07%	n/a	0.01%
GS UN Equity	Goldman Sachs Group Inc	GS	318.5	92.86	1.83	6.18	29,575	29 575	0.10%	0.00%	0.01%
SBAC UW Equity	SBA Communications Cor	SBAC	699.9	52.60	1.22	14.07	36,814	36 814	0.13%	0.00%	0.02%
SRE UN Equity	Sempra Energy	SRE	343.9	200.15	2.50	5.90	68,829	68 829	0.24%	0.01%	0.01%
MCO UN Equity	Moody's Corp	MCO	111.9	320.32	0.58	29.00	35,850	35 850	0.12%	0.00%	0.04%
BKNG UW Equity	Booking Holdings Inc	BKNG	289.3	119.81	3.49	5.84	34,656	34 656	0.12%	0.00%	0.01%
FFIV UW Equity	F5 Networks Inc	FFIV	187.7	295.46	0.76	9.80	55,462	55 462	0.19%	0.00%	0.02%
AKAM UW Equity	Akamai Technologies Inc	AKAM	40.9	1,743.01	n/a	10.08	71,374	71 374	0.25%	n/a	0.02%
MKTX UW Equity	MarketAxess Holdings Inc	MKTX	61.2	123.33	n/a	11.50	7,544	7 544	0.03%	n/a	0.00%
DVN UN Equity	Devon Energy Corp	DVN	162.7	109.96	n/a	11.87	17,891	17 891	0.06%	n/a	0.01%
GOOGL UW Equity	Alphabet Inc	GOOGL	38.0	485.81	0.49	n/a	18,447	-	0.00%	0.00%	n/a
TFX UN Equity	Teleflex Inc	TFX	382.8	9.31	4.73	5.00	3,564	3 564	0.01%	0.00%	0.00%
ALLE UN Equity	Allegion plc	ALLE	300.5	1,491.02	n/a	15.77	448,009	448 009	1.55%	n/a	0.24%
NFLX UW Equity	Netflix Inc	NFLX	46.5	338.98	0.40	9.45	15,768	15 768	0.05%	0.00%	0.01%
A UN Equity	Agilent Technologies Inc	A	441.0	509.63	n/a	31.47	224,755	224 755	0.78%	n/a	0.24%
ANTM UN Equity	Anthem Inc	ANTM	92.2	100.73	1.27	5.59	9,291	9 291	0.03%	0.00%	0.00%
CME UW Equity	CME Group Inc	CME	308.3	101.45	0.71	8.15	31,278	31 278	0.11%	0.00%	0.01%
JNPR UN Equity	Juniper Networks Inc	JNPR	251.5	268.40	1.42	12.57	67,504	67 504	0.23%	0.00%	0.03%
BLK UN Equity	BlackRock Inc	BLK	358.5	160.66	2.00	7.16	60,844	60 844	0.21%	0.00%	0.02%
DTE UN Equity	DTE Energy Co	DTE	331.8	21.41	3.74	7.83	7,103	7 103	0.02%	0.00%	0.00%
CE UN Equity	Celanese Corp	CE	152.5	576.01	2.52	7.13	87,832	87 832	0.30%	0.01%	0.02%
NDAQ UW Equity	Nasdaq Inc	NDAQ	192.1	114.23	3.56	6.33	21,944	21 944	0.08%	0.00%	0.00%
PM UN Equity	Philip Morris International I	PM	164.3	124.25	1.58	9.29	20,409	20 409	0.07%	0.00%	0.01%
IR UN Equity	Ingersoll Rand Inc	IR	118.3	107.46	2.31	4.39	12,712	12 712	0.04%	0.00%	0.00%
CRM UN Equity	salesforce.com Inc	CRM	1,557.3	74.10	6.48	6.43	115,395	115 395	0.43%	0.03%	0.03%
HII UN Equity	Huntington Ingalls Industrie	HII	910.0	253.67	n/a	14.85	230,840	230 840	0.80%	n/a	0.15%
MET UN Equity	MetLife Inc	MET	417.1	35.62	n/a	11.20	14,050	14 050	0.05%	n/a	0.01%
UA UN Equity	Under Armour Inc	UA	40.5	141.40	2.91	40.00	5,726	5 726	0.02%	0.00%	0.01%
TPR UN Equity	Tapestry Inc	TPR	907.7	37.23	4.94	7.07	33,792	33 792	0.12%	0.01%	0.01%
CSX UW Equity	CSX Corp	CSX	231.5	10.13	n/a	12.47	2,345	2 345	0.01%	n/a	0.00%
EW UN Equity	Edwards Lifesciences Corp	EW	277.4	15.84	n/a	9.07	4,394	4 394	0.02%	n/a	0.00%
AMP UN Equity	Ameriprise Financial Inc	AMP	765.1	77.58	1.34	6.44	59,353	59 353	0.21%	0.00%	0.01%
ZBRA UW Equity	Zebra Technologies Corp	ZBRA	621.7	79.41	n/a	13.33	49,372	49 372	0.17%	n/a	0.02%
FTI UN Equity	TechnipFMC PLC	FTI	120.3	155.25	2.68	n/a	18,672	-	0.00%	0.00%	n/a
ZBH UN Equity	Zimmer Biomet Holdings Ir	ZBH	53.3	257.11	n/a	0.90	13,714	13 714	0.05%	n/a	0.00%
CBRE UN Equity	CBRE Group Inc	CBRE	449.4	6.17	2.11	7.75	2,773	2 773	0.01%	0.00%	0.00%
MA UN Equity	Mastercard Inc	MA	207.0	137.39	0.70	2.63	28,447	28 447	0.10%	0.00%	0.00%
KMX UN Equity	CarMax Inc	KMX	335.3	47.36	n/a	8.45	15,879	15 879	0.05%	n/a	0.00%
ICE UN Equity	Intercontinental Exchange	ICE	992.5	343.64	0.47	20.14	341,075	341 075	1.19%	0.01%	0.24%
FIS UN Equity	Fidelity National Informatio	FIS	164.2	93.24	n/a	10.37	15,306	15 306	0.05%	n/a	0.01%
CMG UN Equity	Chipotle Mexican Grill Inc	CMG	542.9	101.10	1.19	9.26	54,910	54 910	0.19%	0.00%	0.02%
WYNN UW Equity	Wynn Resorts Ltd	WYNN	619.5	146.78	0.95	10.80	90,945	90 945	0.31%	0.00%	0.03%
LYV UN Equity	Live Nation Entertainment	LYV	28.0	1,254.72	n/a	25.35	35,092	35 092	0.12%	n/a	0.03%
AIZ UN Equity	Assurant Inc	AIZ	107.8	71.33	n/a	10.50	7,693	7 693	0.03%	n/a	0.00%
NRG UN Equity	NRG Energy Inc	NRG	217.3	53.20	n/a	n/a	11,558	-	0.00%	n/a	n/a
MNST UW Equity	Monster Beverage Corp	MNST	59.6	122.15	2.06	39.60	7,286	7 286	0.03%	0.00%	0.01%
RF UN Equity	Regions Financial Corp	RF	244.1	30.75	3.00	n/a	7,507	-	0.00%	0.00%	n/a
MOS UN Equity	Mosaic Co/The	MOS	960.2	11.44	5.42	1.86	10,984	10 984	0.04%	0.00%	0.00%
EXPE UW Equity	Expedia Group Inc	EXPE	527.4	81.36	n/a	12.34	42,909	42 909	0.15%	n/a	0.02%
EVRG UN Equity	Evergy Inc	EVRG	379.1	17.89	1.12	41.00	6,782	6 782	0.02%	0.00%	0.01%
DISCA UW Equity	Discovery Inc	DISCA	135.7	92.55	n/a	10.17	12,559	12 559	0.04%	n/a	0.00%
CF UN Equity	CF Industries Holdings Inc	CF	226.7	51.31	3.94	6.41	11,630	11 630	0.04%	0.00%	0.00%
LDOS UN Equity	Leidos Holdings Inc	LDOS	160.2	21.38	n/a	4.03	3,425	3 425	0.01%	n/a	0.00%
GOOG UW Equity	Alphabet Inc	GOOG	273.9	30.28	3.96	7.33	8,476	8 476	0.02%	0.00%	0.00%

TEL UN Equity	TE Connectivity Ltd	TEL	142.2	89.51	1.52	10.71	12,728	12,728	0.04%	0.00%	0.00%
COO UN Equity	Cooper Cos Inc/The	COO	333.6	1,495.00	n/a	15.77	498,778	498,778	1.73%	n/a	0.27%
DFS UN Equity	Discover Financial Service	DFS	53.3	340.18	0.02	8.80	18,145	18,145	0.06%	0.00%	0.01%
V UN Equity	Visa Inc	V	330.0	98.18	1.06	9.33	32,403	32,403	0.11%	0.00%	0.01%
MAA UN Equity	Mid-America Apartment Co	MAA	306.4	57.73	3.06	0.59	17,690	17,690	0.06%	0.00%	0.00%
XYL UN Equity	Xylem Inc/NY	XYL	1,686.0	204.18	0.59	13.89	344,249	344,249	1.19%	0.01%	0.17%
MPC UN Equity	Marathon Petroleum Corp	MPC	114.4	117.44	3.40	n/a	13,431	-	0.00%	0.00%	n/a
AMD UW Equity	Advanced Micro Devices Ir	AMD	180.0	83.28	1.25	9.80	14,987	14,987	0.05%	0.00%	0.01%
TSCO UW Equity	Tractor Supply Co	TSCO	650.7	27.78	8.35	1.78	18,076	18,076	0.06%	0.01%	0.00%
RMD UN Equity	ResMed Inc	RMD	116.2	144.74	1.11	13.64	16,822	16,822	0.06%	0.00%	0.01%
MTD UN Equity	Mettler-Toledo Internationa	MTD	1,174.1	83.73	n/a	27.35	98,304	98,304	0.34%	n/a	0.09%
CPRT UW Equity	Copart Inc	CPRT	144.9	170.63	0.01	11.87	24,724	24,724	0.09%	0.00%	0.01%
FTNT UW Equity	Fortinet Inc	FTNT	24.0	972.47	n/a	7.41	23,311	23,311	0.08%	n/a	0.01%
ALB UN Equity	Albemarle Corp	ALB	236.0	106.85	n/a	10.00	25,214	25,214	0.09%	n/a	0.01%
APA UW Equity	Apache Corp	APA	106.4	87.21	1.77	9.58	9,275	9,275	0.03%	0.00%	0.00%
ESS UN Equity	Essex Property Trust Inc	ESS	161.8	119.66	n/a	17.10	19,365	19,365	0.07%	n/a	0.01%
O UN Equity	Realty Income Corp	O	377.5	9.11	1.10	-22.71	3,439	3,439	0.01%	0.00%	0.00%
STX UW Equity	Seagate Technology PLC	STX	65.2	204.48	4.06	2.01	13,334	13,334	0.05%	0.00%	0.00%
WRK UN Equity	Westrock Co	WRK	345.0	61.58	4.56	3.89	21,248	21,248	0.07%	0.00%	0.00%
INFO UN Equity	IHS Markit Ltd	INFO	256.5	49.31	5.27	5.18	12,650	12,650	0.04%	0.00%	0.00%
WAB UN Equity	Westinghouse Air Brake T	WAB	259.6	34.38	2.33	-4.10	8,926	8,926	0.03%	0.00%	0.00%
POOL UW Equity	Pool Corp	POOL	398.4	78.54	0.67	12.18	31,287	31,287	0.11%	0.00%	0.01%
WDC UW Equity	Western Digital Corp	WDC	190.3	61.11	0.79	2.93	11,629	11,629	0.04%	0.00%	0.00%
PEP UW Equity	PepsiCo Inc	PEP	302.5	36.20	n/a	1.86	10,951	10,951	0.04%	n/a	0.00%
FANG UW Equity	Diamondback Energy Inc	FANG	1,382.0	139.74	2.93	4.81	193,115	193,115	0.67%	0.02%	0.03%
MXIM UW Equity	Maxim Integrated Products	MXIM	157.8	28.99	5.18	13.67	4,575	4,575	0.02%	0.00%	0.00%
NOW UN Equity	ServiceNow Inc	NOW	267.4	68.82	n/a	11.65	18,403	18,403	0.06%	n/a	0.01%
CHD UN Equity	Church & Dwight Co Inc	CHD	191.8	491.35	n/a	30.17	94,241	94,241	0.33%	n/a	0.10%
DRE UN Equity	Duke Realty Corp	DRE	247.3	93.75	1.02	8.53	23,185	23,185	0.08%	0.00%	0.01%
FRT UN Equity	Federal Realty Investment	FRT	370.6	37.22	2.53	4.46	13,792	13,792	0.05%	0.00%	0.00%
MGM UN Equity	MGM Resorts Internationa	MGM	75.6	74.54	5.67	2.86	5,638	5,638	0.02%	0.00%	0.00%
AEP UW Equity	American Electric Power C	AEP	493.3	21.82	0.05	6.00	10,761	10,761	0.04%	0.00%	0.00%
VNT UN Equity	Vontier Corp	VNT	496.2	82.32	3.40	7.24	40,844	40,844	0.14%	0.00%	0.01%
JBHT UW Equity	JB Hunt Transport Service	JBHT	105.5	126.44	0.85	13.50	13,340	13,340	0.05%	0.00%	0.01%
LRCX UW Equity	Lam Research Corp	LRCX	145.1	338.22	1.54	12.69	49,072	49,072	0.17%	0.00%	0.02%
MHK UN Equity	Mohawk Industries Inc	MHK	71.2	97.58	n/a	6.70	6,947	6,947	0.02%	n/a	0.00%
PNR UN Equity	Pentair PLC	PNR	165.9	45.48	1.67	9.20	7,546	7,546	0.03%	0.00%	0.00%
VRTX UW Equity	Vertex Pharmaceuticals Inc	VRTX	260.5	272.36	n/a	38.81	70,941	70,941	0.25%	n/a	0.09%
AMCR UN Equity	Amcor PLC	AMCR	1,568.5	11.05	4.16	6.89	17,332	17,332	0.06%	0.00%	0.00%
FB UW Equity	Facebook Inc	FB	2,404.3	266.95	n/a	23.25	641,823	641,823	2.22%	n/a	0.52%
TMUS UW Equity	T-Mobile US Inc	TMUS	1,237.8	115.07	n/a	19.10	142,435	142,435	0.49%	n/a	0.09%
URI UN Equity	United Rentals Inc	URI	72.1	173.33	n/a	-2.06	12,494	12,494	0.04%	n/a	0.00%
ARE UN Equity	Alexandria Real Estate Eq	ARE	45.0	264.84	n/a	16.00	11,930	11,930	0.04%	n/a	0.01%
ABMD UW Equity	ABIOMED Inc	ABMD	126.1	161.87	2.62	4.99	20,414	20,414	0.07%	0.00%	0.00%
DAL UN Equity	Delta Air Lines Inc	DAL	637.9	30.99	n/a	3.50	19,767	19,767	0.07%	n/a	0.00%
UAL UW Equity	United Airlines Holdings Inc	UAL	291.0	34.99	n/a	-0.70	10,182	10,182	0.04%	n/a	0.00%
NWS UW Equity	News Corp	NWS	199.6	14.06	1.42	29.20	2,806	2,806	0.01%	0.00%	0.00%
CNC UN Equity	Centene Corp	CNC	579.5	57.83	n/a	13.23	33,511	33,511	0.12%	n/a	0.02%
MLM UN Equity	Martin Marietta Materials Ir	MLM	62.3	235.17	0.97	8.88	14,644	14,644	0.05%	0.00%	0.00%
TER UW Equity	Teradyne Inc	TER	166.0	80.97	0.49	n/a	13,444	-	0.00%	0.00%	n/a
PYPL UW Equity	PayPal Holdings Inc	PYPL	1,173.3	198.08	n/a	21.64	232,407	232,407	0.80%	n/a	0.17%
DISH UW Equity	DISH Network Corp	DISH	286.9	28.53	n/a	2.84	8,184	8,184	0.03%	n/a	0.00%
ALXN UW Equity	Alexion Pharmaceuticals Ir	ALXN	741.1	46.77	5.99	5.00	34,662	34,662	0.12%	0.01%	0.01%
DOW UN Equity	Dow Inc	DOW	219.2	114.82	n/a	12.20	25,165	25,165	0.09%	n/a	0.01%
RE UN Equity	Everest Re Group Ltd	RE	40.0	198.65	3.12	10.20	7,940	7,940	0.03%	0.00%	0.00%
TDY UN Equity	Teledyne Technologies Inc	TDY	36.9	312.60	n/a	11.10	11,524	11,524	0.04%	n/a	0.00%
NWSA UW Equity	News Corp	NWSA	389.0	14.13	1.42	29.20	5,496	5,496	0.02%	0.00%	0.01%
EXC UW Equity	Exelon Corp	EXC	973.9	35.84	4.27	1.97	34,906	34,906	0.12%	0.01%	0.00%
GPN UN Equity	Global Payments Inc	GPN	299.2	178.80	0.44	19.97	53,505	53,505	0.19%	0.00%	0.04%
CCI UN Equity	Crown Castle International	CCI	419.7	167.53	2.87	17.43	70,307	70,307	0.24%	0.01%	0.04%
APTV UN Equity	Aptiv PLC	APTV	270.0	93.52	n/a	10.69	25,253	25,253	0.09%	n/a	0.01%
AAP UN Equity	Advance Auto Parts Inc	AAP	69.1	155.15	0.64	12.79	10,727	10,727	0.04%	0.00%	0.00%
ALGN UW Equity	Align Technology Inc	ALGN	78.8	315.94	n/a	13.66	24,892	24,892	0.09%	n/a	0.01%
ILMN UW Equity	Illumina Inc	ILMN	146.4	308.85	n/a	14.23	45,203	45,203	0.16%	n/a	0.02%
LKQ UW Equity	LKQ Corp	LKQ	304.3	27.99	n/a	7.90	8,517	8,517	0.03%	n/a	0.00%
NLSN UN Equity	Nielsen Holdings PLC	NLSN	356.8	14.27	1.68	12.00	5,091	5,091	0.02%	0.00%	0.00%
GRMN UW Equity	Garmin Ltd	GRMN	191.2	95.63	2.55	5.85	18,288	18,288	0.06%	0.00%	0.00%
ZTS UN Equity	Zoetis Inc	ZTS	475.1	164.75	0.49	8.80	78,280	78,280	0.27%	0.00%	0.02%
DLR UN Equity	Digital Realty Trust Inc	DLR	88.5	763.02	1.39	17.80	67,571	67,571	0.23%	0.00%	0.04%
EQIX UW Equity	Equinix Inc	EQIX	269.0	147.61	3.04	13.63	39,706	39,706	0.14%	0.00%	0.02%
LVS UN Equity	Las Vegas Sands Corp	LVS	763.8	46.18	n/a	8.40	35,272	35,272	0.12%	n/a	0.01%
DISCK UW Equity	Discovery Inc	DISCK	340.2	19.27	n/a	4.03	6,555	6,555	0.02%	n/a	0.00%

Notes

[1] Bloomberg Professional as of September 30, 2020
[2] Bloomberg Professional as of September 30, 2020
[3] Equals [1]*(1 + 0.50 x [2]) + [2]
[4] See AEB-5R3 CAPM
[5] Equals [3] - [4]

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES
(Dividend Yield and Growth Rate sourced from the S&P Earnings and Estimates Report)

[1] Estimated Weighted Average Dividend Yield		1.68%	
[2] Estimated Weighted Average Long-Term Growth Rate		12.27%	
[3] S&P 500 Estimated Required Market Return		14.05%	
[4] Risk-Free Rate	1.42%	1.64%	3.00%
[5] Implied Market Risk Premium	12.63%	12.41%	11.05%

Notes
[1] S&P Earnings and Estimates Report, September 30, 2020
[2] S&P Earnings and Estimates Report, September 30, 2020
[3] Equals [1]*(1 + 0.50 x [2]) + [2]
[4] See AEB-5RB CAPM
[5] Equals [3] - [4]

CAPITAL ASSET PRICING MODEL
(Market Return sourced from Bloomberg)

	[4]	[5]	[6]	[7]
	Risk-Free Rate	Average Beta	Market Risk Premium	ROE
Proxy Group Average Bloomberg Beta				
[1] Current 30-day average of 30-year U.S. Treasury bond yield	1.42%	0.817	12.01%	11.23%
[2] Blue Chip Consensus Forecast (Q4 2020 - Q4 2021)	1.64%	0.817	11.79%	11.27%
[3] Projected 30-year U.S. Treasury bond yield (2022- 2026)	3.00%	0.817	10.43%	11.52%
			Mean:	11.34%
Proxy Group Average Value Line Beta				
[1] Current 30-day average of 30-year U.S. Treasury bond yield	1.42%	0.875	12.01%	11.93%
[2] Blue Chip Consensus Forecast (Q4 2020 - Q4 2021)	1.64%	0.875	11.79%	11.96%
[3] Projected 30-year U.S. Treasury bond yield (2022- 2026)	3.00%	0.875	10.43%	12.13%
			Mean:	12.01%

[1] Source: Bloomberg Professional, 30-day average of 30-year Treasury bond, as of September 30, 2020
[2] Blue Chip Financial Forecasts, Vol. 39, No. 9, September 1, 2020, at 2
[3] Source: Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020, at 14
[4] See Notes [1], [2], and [3]
[5] Source: Bloomberg Professiona (10-Year Betas as of September 30, 2020) and Value Line (September 11, 2020; August 14, 2020; and July 24, 2020)
[6] Exhibit AEB-4RB
[7] Equals [4] + [5] x [6]

CAPITAL ASSET PRICING MODEL
(Market Return sourced from the S&P Earnings and Estimates Report)

	[4]	[5]	[6]	[7]
	Risk-Free Rate	Average Beta	Market Risk Premium	ROE
Proxy Group Average Bloomberg Beta				
[1] Current 30-day average of 30-year U.S. Treasury bond yield	1.42%	0.817	12.63%	11.74%
[2] Blue Chip Consensus Forecast (Q4 2020 - Q4 2021)	1.64%	0.817	12.41%	11.78%
[3] Projected 30-year U.S. Treasury bond yield (2022- 2026)	3.00%	0.817	11.05%	12.03%
			Mean:	11.85%
Proxy Group Average Value Line Beta				
[1] Current 30-day average of 30-year U.S. Treasury bond yield	1.42%	0.875	12.63%	12.47%
[2] Blue Chip Consensus Forecast (Q4 2020 - Q4 2021)	1.64%	0.875	12.41%	12.50%
[3] Projected 30-year U.S. Treasury bond yield (2022- 2026)	3.00%	0.875	11.05%	12.67%
			Mean:	12.55%

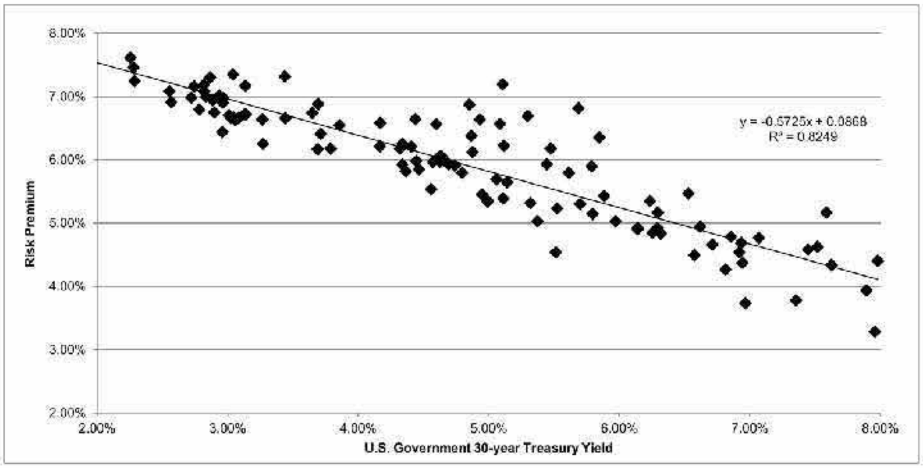
[1] Source: Bloomberg Professional, 30-day average of 30-year Treasury bond, as of September 30, 2020
[2] Blue Chip Financial Forecasts, Vol. 39, No. 9, September 1, 2020, at 2
[3] Source: Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020, at 14
[4] See Notes [1], [2], and [3]
[5] Source: Bloomberg Professiona (10-Year Betas as of September 30, 2020) and Value Line (September 11, 2020; August 14, 2020; and July 24, 2020)
[6] Exhibit AEB-4.5RB
[7] Equals [4] + [5] x [6]

Risk Premium -- Electric Utilities

	[1] Average Authorized Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1992.1	12.38%	7.98%	4.40%
1992.2	11.83%	7.89%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.77%
1993.2	11.64%	6.86%	4.79%
1993.3	11.15%	6.31%	4.84%
1993.4	11.04%	6.14%	4.90%
1994.1	11.07%	6.57%	4.49%
1994.2	11.13%	7.35%	3.78%
1994.3	12.75%	7.58%	5.17%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.34%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.71%	4.66%
1995.4	11.58%	6.23%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.96%	3.74%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.81%	4.27%
1997.2	11.62%	6.93%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.14%	4.92%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.47%	6.18%
1998.4	12.30%	5.10%	7.20%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.79%	5.15%
1993.3	11.15%	6.31%	4.84%
1999.4	11.10%	6.25%	4.85%
2000.1	11.21%	6.29%	4.92%
2000.2	11.00%	5.97%	5.03%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.44%	5.93%
2001.2	11.00%	5.70%	5.30%
2001.3	10.76%	5.52%	5.23%
2001.4	11.99%	5.30%	6.70%
2002.1	10.05%	5.51%	4.54%
2002.2	11.41%	5.61%	5.79%
2002.3	11.65%	5.08%	6.57%
2002.4	11.57%	4.93%	6.64%
2003.1	11.72%	4.85%	6.87%
2003.2	11.16%	4.60%	6.56%
2003.3	10.50%	5.11%	5.39%
2003.4	11.34%	5.11%	6.23%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.32%	5.32%
2004.3	10.75%	5.06%	5.69%
2004.4	11.24%	4.86%	6.38%
2005.1	10.63%	4.69%	5.93%
2005.2	10.31%	4.47%	5.85%
2005.3	11.08%	4.44%	6.65%
2005.4	10.63%	4.68%	5.95%
2006.1	10.70%	4.63%	6.06%
2006.2	10.79%	5.14%	5.65%
2006.3	10.35%	4.99%	5.35%
2006.4	10.65%	4.74%	5.91%
2007.1	10.59%	4.80%	5.80%
2007.2	10.33%	4.99%	5.34%
2007.3	10.40%	4.95%	5.45%
2007.4	10.65%	4.61%	6.04%
2008.1	10.62%	4.41%	6.21%
2008.2	10.54%	4.57%	5.97%
2008.3	10.43%	4.44%	5.98%
2008.4	10.39%	3.65%	6.74%
2009.1	10.75%	3.44%	7.31%
2009.2	10.75%	4.17%	6.58%
2009.3	10.50%	4.32%	6.18%
2009.4	10.59%	4.34%	6.26%
2010.1	10.59%	4.62%	5.97%
2010.2	10.18%	4.36%	5.82%
2010.3	10.40%	3.86%	6.55%
2010.4	10.38%	4.17%	6.21%
2011.1	10.09%	4.56%	5.53%
2011.2	10.26%	4.34%	5.92%
2011.3	10.57%	3.69%	6.88%

Risk Premium -- Electric Utilities

	[1]	[2]	[3]
	Average Authorized Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
2011.4	10.39%	3.04%	7.35%
2012.1	10.30%	3.14%	7.17%
2012.2	9.95%	2.93%	7.02%
2012.3	9.90%	2.74%	7.16%
2012.4	10.16%	2.86%	7.30%
2013.1	9.85%	3.13%	6.72%
2013.2	9.86%	3.14%	6.72%
2013.3	10.12%	3.71%	6.41%
2013.4	9.97%	3.79%	6.18%
2014.1	9.86%	3.69%	6.17%
2014.2	10.10%	3.44%	6.66%
2014.3	9.90%	3.26%	6.64%
2014.4	9.94%	2.96%	6.98%
2015.1	9.64%	2.55%	7.08%
2015.2	9.83%	2.88%	6.94%
2015.3	9.40%	2.96%	6.44%
2015.4	9.86%	2.96%	6.90%
2016.1	9.70%	2.72%	6.98%
2016.2	9.48%	2.57%	6.91%
2016.3	9.74%	2.28%	7.46%
2016.4	9.83%	2.83%	7.00%
2017.1	9.72%	3.04%	6.67%
2017.2	9.64%	2.90%	6.75%
2017.3	10.00%	2.82%	7.18%
2017.4	9.91%	2.82%	7.09%
2018.1	9.69%	3.02%	6.66%
2018.2	9.75%	3.09%	6.66%
2018.3	9.69%	3.06%	6.63%
2018.4	9.52%	3.27%	6.25%
2019.1	9.72%	3.01%	6.71%
2019.2	9.58%	2.78%	6.79%
2019.3	9.53%	2.29%	7.24%
2019.4	9.87%	2.25%	7.62%
2020.1	9.72%	1.89%	7.83%
2020.2	9.58%	1.38%	8.20%
2020.3	9.30%	1.37%	7.93%
AVERAGE	10.70%	4.72%	5.98%
MEDIAN	10.63%	4.69%	6.12%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.90822
R Square	0.82486
Adjusted R Square	0.82331
Standard Error	0.00425
Observations	115

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.0096	0.0096	532.2058	0.0000
Residual	113	0.0020	0.0000		
Total	114	0.0117			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0868	0.00124	70.20182	0.00000	0.08434	0.08924	0.08434	0.08924
X Variable 1	-0.5725	0.02482	-23.06959	0.00000	-0.62165	-0.52332	-0.62165	-0.52332

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	1.42%	7.86%	9.29%
Blue Chip Consensus Forecast (Q4 2020 - Q4 2021) [5]	1.64%	7.74%	9.38%
Blue Chip Consensus Forecast (2022-2026) [6]	3.00%	6.96%	9.96%
AVERAGE			9.54%

Notes:
[1] Source: Regulatory Research Associates, accessed October 5, 2020
[2] Source: Bloomberg Professional, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] – Column [2]
[4] Source: Bloomberg Professional, 30-Day Average as of September 30, 2020
[5] Source: Blue Chip Financial Forecasts, Vol. 39, No. 9, September 1, 2020, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020, at 14
[7] See notes [4] & [5]
[8] Equals 0.086791 + (-0.572488 x Column [6])
[9] Equals Column [6] + Column [7]

EXPECTED EARNINGS ANALYSIS

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Value Line ROE 2023-2025	Value Line Total Capital 2019	Value Line Common Equity Ratio 2019	Total Equity 2019	Value Line Total Capital 2023-2025	Value Line Common Equity Ratio 2023-2025	Total Equity 2023-2025	Compound Annual Growth Rate	Adjustment Factor	Adjusted Return on Common Equity
ALLETE, Inc.	ALE	8.00%	3632.8	61.40%	2,231	4775	59.00%	2,817	4.78%	1.023	8.19%
Ameren Corporation	AEE	10.00%	17116	47.10%	8,062	24500	49.00%	12,005	8.29%	1.040	10.40%
American Electric Power Company, Inc	AEP	10.50%	44759	43.90%	19,649	61200	48.00%	29,376	8.38%	1.040	10.92%
DTE Energy Company	DTE	11.00%	27607	42.30%	11,678	39000	41.50%	16,185	6.75%	1.033	11.36%
Duke Energy Corporation	DUK	8.50%	101807	44.10%	44,897	123600	45.00%	55,620	4.38%	1.021	8.68%
Exelon Corporation	EXC	9.00%	63943	50.40%	32,227	80300	50.00%	40,150	4.49%	1.022	9.20%
FirstEnergy Corporation	FE	15.50%	26593	26.20%	6,967	35000	34.00%	11,900	11.30%	1.053	16.33%
Evergy, Inc.	EVRG	8.50%	17337	49.40%	8,564	20500	46.50%	9,533	2.16%	1.011	8.59%
OGE Energy Corporation	OGE	12.00%	7334.7	56.40%	4,137	8050	51.00%	4,106	-0.15%	0.999	11.99%
Otter Tail Corporation	OTTR	11.50%	1471.1	53.10%	781	1850	53.00%	981	4.65%	1.023	11.76%
PNM Resources, Inc.	PNM	9.50%	4207.7	39.90%	1,679	5475	49.00%	2,683	9.83%	1.047	9.94%
PPL Corporation	PPL	12.50%	33712	38.50%	12,979	39100	42.50%	16,618	5.07%	1.025	12.81%
Southern Company	SO	12.50%	69594	39.50%	27,490	84000	39.50%	33,180	3.83%	1.019	12.74%
Xcel Energy Inc.	XEL	10.50%	30646	43.20%	13,239	41700	42.50%	17,723	6.01%	1.029	10.81%
Mean		10.68%									10.98%
Mean excluding FE, PPL		10.13%									10.38%
Mean excluding FE, PPL, DTE, SO		9.80%									**10.05%**

Notes:
[1] Source: Value Line (September 11, 2020; August 14, 2020; and July 24, 2020)
[2] Source: Value Line (September 11, 2020; August 14, 2020; and July 24, 2020)
[3] Source: Value Line (September 11, 2020; August 14, 2020; and July 24, 2020)
[4] Equals [2] x [3]
[5] Source: Value Line (September 11, 2020; August 14, 2020; and July 24, 2020)
[6] Source: Value Line (September 11, 2020; August 14, 2020; and July 24, 2020)
[7] Equals [5] x [6]
[8] Equals ([7] / [4]) ^ (1/5) - 1
[9] Equals 2 x (1 + [8]) / (2 + [8])
[10] Equals [1] x [9]

Estimates of Return on Fair Value Increment

Scenario 1: Real Risk Free Rate -- Projected Estimate

Step 1	
Consumer Price Index (YoY % Change) [1]	
2022-2026	2.10%
2027-2031	2.20%
Average	2.15%
Consumer Price Index (All-Urban) [2]	
2021	2.69%
2031	3.39%
Compound Annual Growth Rate	2.35%
GDP Chain-type Price Index (2009=1.000) [2]	
2021	1.18
2031	1.49
Compound Annual Growth Rate	2.36%
Average Inflation Forecast	**2.29%**
Step 2	
Nominal U.S. Treasury Bond Yield, 30-year [1]	
2022-2026	3.00%
2027-2031	3.80%
	3.40%
Real Risk-Free Rate [3]	**1.09%**

Notes:

[1] Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020, at 14

[2] Energy Information Administration, Annual Energy Outlook 2020, Table 20

[3] Equals (3.40% + 1) / (1 + 2.29%) – 1

Estimates of Return on Fair Value Increment

Scenario 2: Real Risk Free Rate -- Projected Estimate

Nominal U.S. Treasury Bond Yield, 30-year [1]		
Projection period:	2022-2026	3.00%
Projection period:	2027-2031	3.80%
		3.40%
180-day average yield on 30-year U.S. Treasury Bonds [2]		1.50%
180-day average yield on 30-year U.S. Treasury Inflation Protected Securities [2]		-0.07%
		1.57%
Real Risk-Free Rate [3]		**1.83%**

Notes:
[1] Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020, at 14
[2] Source: https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=realyieldYear&year=2019
As of September 30, 2020
[3] Equals [1]-[2]

Estimates of Return on Fair Value Increment

Scenario 3: Real Risk Free Rate -- Normalized Risk-Free Rate

Nominal Risk Free Rate [1]	2.50%
180-day average yield on 30-year U.S. Treasury Bonds [2]	1.50%
180-day average yield on 30-year U.S. Treasury Inflation Protected Securities [2]	-0.07%
	1.57%
Real Risk-Free Rate [3]	**0.93%**
	0.47%

Notes:

[1] Duff and Phelps 2020 Valuation Handbook

[2] Source: https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=realyieldYear&year=2019

As of September 30, 2020

[3] Equals [1]-[2]

Estimates of Return on Fair Value Increment

Real Risk-Free Rate Estimates		
	Scenario 1	1.09%
	Scenario 2	1.83%
	Scenario 3	0.93%
	Mean	1.28%

FVI Cost Rate Recommendations

Bulkley recommended rate [1]	1.28%
APS requested rate	**0.80%**

Notes:
[1] Equals the mean of the three scenarios

ARIZONA PUBLIC SERVICE COMPANY
FAIR VALUE RATE OF RETURN
ARIZONA STAFF METHODOLOGY

		Amount ($M)	Weighting		Weighted Amount ($M)	
Original Cost Rate Base (OCRB)	$	8,896.3	50.00%	$	4,448.1	[1]
Replacement Cost New, Depreciated Rate Base (RCND)	$	15,734.1	50.00%		7,867.1	[2]
Fair Value Rate Base (FVRB)					12,315.2	[3]
Appreciation Above OCRB				$	3,418.9	[4]
FVRB / OCRB Multiple					1.38	

Capital			Amount ($M)	Percent	Cost Rate		Weighted Cost Rate
Long-Term Debt	45.33%	$	4,032.7	32.75%	4.10%	[5]	1.34%
Common Equity	54.67%		4,863.6	39.49%	**10.00%**	[6]	3.95%
Capital Financing OCRB		$	8,896.3	72.24%			5.29%
Appreciation Above OCRB Not Recognized on Utility's Books			3,418.9	27.76%	**0.80%**	[7]	0.22%
Total		$	12,315.2	100.00%			5.51%

[1] Rebuttal Testimony of Leland Snook, Attachment LRD-01RB
[2] Rebuttal Testimony of Leland Snook, Attachment LRS 01-RB
[3] Equals [1] + [2]
[4] Equals [3] − OCRB
[5] Company Data
[6] Equals the recommended ROE on OCRB
[7] Equals APS' requested FVI cost rate. See AEB-8RB

ARIZONA PUBLIC SERVICE COMPANY
FAIR VALUE RATE OF RETURN
ARIZONA STAFF METHODOLOGY

	Amount ($M)	Weighting	Weighted Amount ($M)	
Original Cost Rate Base (OCRB)	$ 8,896.3	50.00%	$ 4,448.1	[1]
Replacement Cost New, Depreciated Rate Base (RCND)	$ 15,734.1	50.00%	7,867.1	[2]
Fair Value Rate Base (FVRB)			12,315.2	[3]
Appreciation Above OCRB			$ 3,418.9	[4]
FVRB / OCRB Multiple			1.38	

Capital		Amount ($M)	Percent	Cost Rate		Weighted Cost Rate
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Capital Financing OCRB		$ 8,896.3	72.24%			5.29%
Appreciation Above OCRB Not Recognized on Utility's Books		3,418.9	27.76%	**0.80%**	[7]	0.22%
Total		$ 12,315.2	100.00%			5.51%

[1] Rebuttal Testimony of Leland Snook, Attachment LRD-01RB
[2] Rebuttal Testimony of Leland Snook, Attachment LRS 01-RB
[3] Equals [1] + [2]
[4] Equals [3] − OCRB
[5] Company Data
[6] Equals the recommended ROE on OCRB
[7] Equals APS' requested FVI cost rate. See AEB-8RB

Parcell FVROR using updated Return on the FV increment

As Filed:

Capital Component	Percent	Cost	FVROR
Long-term Debt	32.58%	4.10%	1.34%
Equity	39.30%	9.40%	3.69%
Fair Value Increment	28.12%	0.30%	0.08%
			5.11%

Update Real Rf Rate to Calculate Return on FVI using Parcell Methodology:

Capital Component	Percent	Cost	FVROR
Long-term Debt	32.58%	4.10%	1.34%
Equity	39.30%	9.40%	3.69%
Fair Value Increment	28.12%	0.47%	0.13%
			5.16%

Update to Company's Requested Return on FVI:

Capital Component	Percent	Cost	FVROR
Long-term Debt	32.58%	4.10%	1.34%
Equity	39.30%	9.40%	3.69%
Fair Value Increment	28.12%	0.80%	0.22%
			5.25%

Update ROE to Company's requested ROE:

Capital Component	Percent	Cost	FVROR
Long-term Debt	32.58%	4.10%	1.34%
Equity	39.30%	10.00%	3.93%
Fair Value Increment	28.12%	0.80%	0.22%
			5.49%

Adjustments to Walters ROE -- DCF approach

Bulkley adjustments to the results presented by Walters in Table 7 at page 35

Model structure	Walters growth rate assumption	Mean ROE result
Constant Growth	Analyst estimates of earnings growth rate	**9.47% - 9.50%**
Constant Growth	Calculated "sustainable growth rate"	*Reject*
Multi-Stage Growth	Analyst estimates of earnings growth rate (first 5 years) + Projected GDP growth rate (>year 10)	*Reject*

Adjustments to Walters ROE -- Bond Yield Plus Risk Premium approach

Bulkley adjustments to the results presented by Walters in Table 8 at page 41

Assumption for risk-free rate		Assumption for utility equity risk premium over 30-year T-Bond yield		
		[3] Historical average: Last 5 years (Rf = 2.56%) 7.02%	[4] Most recent: Jan-Jun 2020 (Rf = 1.63%) **7.84%**	[5] Calculated using Bulkley regression equation (Rf = 1.80%) **7.65%**
[1] Short-term projected 30-yr T-Bond yield	**1.80%**	*Reject*	9.64%	9.45%
[2] Current utility bond yields	2.79% - 3.42%	N/A	N/A	N/A

[1] See Walters page 40

[2] See Walters page 40

[3] CCW-12DR Column 4, Line 35 (5-year average risk premium over T-bonds) and Column 2, Lines 31-35 (5-year average T-bond yield)

[4] CCW-12DR Column 3, Line 35 (2020 risk premium over T-bonds) and Column 2, Line 35 (2020 T-bond yield)

[5] See AEB-6RR for regression equation; see Walters page 40 for Walters projected T-bond yield (i.e., risk-free rate) assumption

Adjustments to Walters ROE -- CAPM

Bulkley adjustments to the results presented by Walters in CCW-17DR and Table 10 at page 51

[1] Assumption for risk-free rate = **1.80%**

Assumption for market risk premium				Assumption for average Beta of 14-company proxy group		
				[4] Current ValueLine (adjusted, weekly)	[5] Past ValueLine (adjusted, weekly)	[6] Current Market Intelligence (raw, daily)
Market return [2]		Market return less risk-free rate [3]		**0.893**	0.72	0.691
Historical return + expected inflation ("risk premium method")	11.20%	9.40%	(MRP #1)	*Reject*	*Reject*	*Reject*
Constant growth DCF equation	**13.38%**	11.60%	(MRP #2)	12.16%	*Reject*	*Reject*
Two-stage DCF equation ("FERC method")	11.91%	10.10%	(MRP #3)	*Reject*	*Reject*	*Reject*

[1] See Walters page 50 and 51
[2] See Walters page 45 and 46
[3] Equals [2] minus [1]. Walters rounds the result to the nearest tenth of a percent.
[4] Calculated from individual company Betas provided in CCW-16DR. Walters presents the proxy group average rounded to the nearest hundredth, but uses the average rounded to the nearest thousandth in his calculations.
[5] See CCW-16DR
[6] Calculated from individual company Betas provided in CCW-16DR. Walters presents the proxy group average rounded to the nearest hundredth, but uses the average rounded to the nearest thousandth in his calculations.

ATTACHMENT 11

REBUTTAL TESTIMONY OF TODD A. SHIPMAN

On Behalf of Arizona Public Service Company

Docket No. E-01345A-19-0236

November 6, 2020

Table of Contents

Attachments

REBUTTAL TESTIMONY OF TODD A. SHIPMAN
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-19-0236)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Todd A. Shipman. I am an Executive Advisor to Concentric Energy Advisors, Inc. (Concentric), which has its headquarters at 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am testifying on behalf of Arizona Public Service Company (APS or Company).

Q. PLEASE SUMMARIZE YOUR EDUCATION AND BUSINESS EXPERIENCE.

A. I graduated from Texas Christian University with a Bachelor of Business Administration (B.B.A.) degree with a major in economics and from Texas Tech University School of Law with a Juris Doctor (J.D.) degree. I was awarded the Chartered Financial Analyst (C.F.A.) designation in 1989. I have 35 years of experience in the financial and utility industries. I began in the financial industry as an analyst with a research firm that specialized in analyzing and reporting the investment implications of the actions and behavior of utility regulators. Subscribers to the research included investment bankers and analysts at major Wall Street firms, large institutional investors such as insurance companies and mutual funds, utilities, and regulators.

I then joined an independent power producer. My primary responsibility was in regulatory affairs. I coordinated and managed its interventions in state regulatory proceedings. I also assisted in its development efforts, analyzing avoided-cost rates and regulatory policies toward non-utility power production, and in its investor relations.

I spent the last 21 years of that stage of my career at S&P Global Ratings (S&P), a major ratings agency that has been in business over 150 years and issues more than one million ratings on over $46 trillion of debt across all global capital markets. I performed credit surveillance of utilities, pipelines, midstream energy, and diversified energy companies. In the final ten years at S&P, I was the Sector Specialist on the North American utilities team. In that role, I was the lead analyst on the team charged with ensuring ratings quality, assisting in the training and development of new analysts, and creating the criteria used to establish utility credit ratings. I also led outreach efforts to investors and the regulatory community and performed a lead analytical role in the development and application of global ratings criteria for hybrid capital securities.

Q. PLEASE DESCRIBE THE RESPONSIBILITIES OF YOUR CURRENT POSITION.

A. After retiring from S&P, I became a management consultant specializing in advising utilities and other entities on credit and ratings issues, balance sheet management, and capital markets strategies. I also continued to teach advanced undergraduate finance courses at Boston University's Questrom School of Business for a while as an adjunct faculty member. I joined Concentric in August 2018 as an Executive Advisor. My curriculum vitae appears as Attachment TAS-01RB.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON CREDIT RATING ISSUES?

A. Yes. As an expert on credit ratings, I have participated in proceedings before the Federal Energy Regulatory Commission, the Hawaii Public Utilities Commission, the Wisconsin Public Service Commission, the California Public Utilities Commission, the New York Public Service Commission, the Virginia State Corporation Commission, the Mississippi Public Service Commission, the New

Mexico Public Regulation Commission, the Texas Public Utility Commission, and the Arizona Corporation Commission.

Q. HAVE YOU FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. No.

Q. ARE YOU SPONSORING ANY ATTACHMENTS THAT ACCOMPANY YOUR TESTIMONY?

A. Yes. Attachment TAS-01RB is my curriculum vitae. Attachment TAS-02RB contains the ratings scales of the two major rating agencies.

Q. WHAT IS THE PURPOSE OF YOUR PREPARED REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. I address the negative effect on the Company's credit quality of the intervenor and Staff recommendations. In addition, I respond to specific recommendations in the prepared direct testimony filed by:

- Christopher C. Walters on behalf of Federal Executive Agencies (FEA), and
- Richard Gayer, Intervenor

Q. PLEASE SUMMARIZE YOUR PREPARED REBUTTAL TESTIMONY.

A. My prepared rebuttal testimony consists of the following:

- An overview and explanation of credit ratings
- The role credit ratings play in the capital markets and in turn how capital markets play a role in credit ratings
- The effect that credit ratings have on utilities and customers
- The benefits that customers have already experienced from past improvements to APS's credit ratings
- The risk of a downgrade of APS's credit ratings

- The effect of a utility's regulatory environment on its ratings
- The backdrop of this case amid a negative credit rating environment due to capital market and macroeconomic fallout from the COVID-19 crisis, and
- The importance of this and future decisions on APS, its ratings and its customers

II. CREDIT RATINGS AND CAPITAL MARKETS

A. *Determining a Credit Rating*

Q. WHAT IS A CREDIT RATING, AND HOW DOES IT DIFFER FROM OTHER MEASURES OF THE FINANCIAL CONDITION OF A UTILITY?

A. A credit rating summarizes credit risk, which is primarily the ability and willingness of an issuer to fulfill its financial obligations in full and on time. Ratings first address the relative probability that an issuer or a specific debt issuance will experience default, i.e., the failure to pay either the required periodic payment or the principal when it matures under the terms of the security. As a secondary matter, some ratings incorporate the concept of recovery into the analysis. Recovery looks at the prospect of being made whole in the event of a default.

Credit ratings have a longer-term focus than other common financial benchmarks such as earnings-per-share, rate of return, and the market prices of a company's securities at a particular point in time. Ratings are an objective, independent opinion offered by firms that have no financial stake in the outcome of its analysis. The combination of the long-term and independent nature of credit ratings offer utility regulators a useful guide to help navigate through the many decisions they must make in the course of balancing the various stakeholder interests that come before them.

Q. IS A CREDIT RATING AN ACCURATE MEASURE OF AN ISSUER'S RISK AND FINANCIAL INTEGRITY?

A. Yes. The historical default experience of issuers validates the usefulness of credit ratings as a measure of risk. From 1994 through 2019, Moody's Investor Service (Moody's) calculated that the five-year average, volume-weighted corporate bond default rate increases as you descend the ratings scale, from a low of 0.4% for the "Aaa" category to 39.55% for the combined "Caa-C" categories. For the investment-grade categories, the rate never gets to 1% and leaps to almost 4%, nearly four times as high, in the first speculative-grade category.[1]

Q. HOW DOES A CREDIT RATING AGENCY ESTABLISH A CREDIT RATING?

A. Ratings are established by a committee that specializes in the industry or industries of the rated entity. Ratings conform to common standards of credit risk by employing ratings criteria that are consistently applied. The analysis centers on two main areas. The quantitative side of the analysis examines financial ratios and other metrics to analyze the financial risk of the issuer. The qualitative side is the assessment of business risk, which is built up from the broad macro risks at the country and industry level. The issuer's more specific risk within its business and economic environment is then determined. For a utility, the major business risks are regulatory risk, operating risk and cash-flow diversity.

Business risk and financial risk can be viewed as complementary sides of the total risk of an entity, so that more of one risk must be offset by less of the other risk to arrive at a given rating. Because utilities are closely regulated and constrained on how much financial metrics vary over time, it is often the qualitative analysis that drives ratings outcomes. In investment-grade categories, which almost all U.S.

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[1] *See* Exhibit 54 in Moody's Investor Service, *Annual Default Study: Defaults will edge higher in 2020*, Jan. 30, 2020.

utilities occupy, qualitative factors are weighted more than financial factors in the credit analysis.

Q. HOW IS BUSINESS RISK MEASURED?

A. The business risk profile for a utility is focused primarily on regulatory risk. Other risk areas include operating risk, diversification, industry risk, and country risk. They are relevant and can sometimes exert influence on the final result, but in the U.S., they are rarely distinguishing factors in the analysis. Because regulatory risk is so important and encompassing, I devote an entire section to the topic (*see* Section III *infra*).

Q. WHAT IS THE MOST DETERMINATIVE FACTOR WHEN ASSESSING A UTILITY'S BUSINESS RISK?

A. The analysis of a utility's business risk, as with any other corporate issuer, revolves around the concept of volatility, especially regarding cash flow. Although rating agencies review and analyze many aspects of a utility's regulatory construct, it all comes down to two things: the ability to earn a compensatory rate of return on its investment, which is tied to financial risk, and the stability of those financial results, which is business risk in a nutshell. Another way to summarize a utility's business risk is to concentrate on regulatory lag. Regulatory lag (the delay between the incurrence of costs and the recovery of those costs in rates) consumes a great deal of rating agency attention in the analysis of business risk. To combat regulatory lag, they look for the degree that adjustment mechanisms and other cost adjustors are employed by a regulator to assist the timely recovery of costs in rates.

Q. CAN YOU PROVIDE AN EXAMPLE THAT SHOWS HOW RATING AGENCIES VALUE THE USE OF ADJUSTMENT MECHANISMS AND ADJUSTORS?

A. Yes. For example, in Moody's methodology, the concept appears in the area they call "Ability to Recover Costs and Earn Returns," which alone accounts for a full

25% of its regulated utility rating scorecard.[2] As they state, "The criteria we consider include provisions and cost recovery mechanisms for operating costs, mechanisms that allow actual operating and/or capital expenditures to be trued-up periodically into rates without having to file a rate case (this may include formula rates, rider and trackers, or the ability to periodically adjust rates for construction work in progress) as well as the process and timeframe of general tariff/base rate cases – those that are fully reviewed by the regulator, generally in a public format that includes testimony of the utility and other stakeholders and interest groups."[3] Moody's also includes an extensive discussion of APS's various cost recovery mechanisms in its credit analysis.[4]

Q. HOW IS FINANCIAL RISK MEASURED?

A. It is mostly a matter of calculating credit metrics for the issuer on both a historical and forecasted basis. The forecasted metrics are more impactful to the analysis, especially if they are expected to differ from the actual metrics recorded by the issuer. There are essentially two types of metrics. Leverage metrics assess the relative burden of debt and other fixed-income obligations compared to the financial responsibility being carried by shareholders. Coverage metrics gauge the issuer's ability to service its fixed-income obligations, much like a mortgage company looks at a homeowner's income compared to the house payment. Credit analysis by a rating agency is more sophisticated than that, however, and a credit analyst will affect numerous adjustments to accurately capture the issuer's financial capabilities and debt burden.

Notably, operating cash flow is emphasized in credit metrics more than the earnings measures used in equity analysis. This difference was most recently exhibited when assessing the effect of tax reform on utilities. For most corporate

[2] Moody's, *Rating Methodology*, pp. 12-15.
[3] *Id*. at 12.
[4] Moody's, *Arizona Public Service Company*, Jan. 27, 2020, p. 4.

issuers and for shareholders, tax reform was beneficial. For utilities and their creditors, though, it was not favorable because of its negative cash-flow impact.

Finally, financial risk also comprises two other vital components – liquidity and financial policy – that are not part of the metric analysis. The latter is especially relevant to a utility's regulator, as it takes a broader and longer-term view of an issuer's financial condition and the prospect for changes to it. The regulator's regard for and support of a utility's balance sheet and the consistency of its support can be a factor in this part of the financial analysis.

Q. WHY IS A GOOD UNDERSTANDING OF CREDIT RATINGS AND THE METHODOLOGIES AND PROCEDURES USED TO ESTABLISH RATINGS IMPORTANT FOR THE PURPOSES OF THIS PROCEEDING?

A. The proper use of credit ratings as a measure of risk and financial integrity requires an in-depth understanding of the ratings process and analytical approach to ratings. A lack of understanding can lead to erroneous and unsupported conclusions about financial risk.

Q. DO YOU HAVE ANY CONCERNS ABOUT FEA WITNESS MR. WALTERS'S USE OF CREDIT RATING ANALYSIS[5] TO MEASURE APS'S FINANCIAL INTEGRITY DEFICIENT? IF SO, PLEASE EXPLAIN.

A. Yes. Mr. Walters omits or misconstrues many parts of the S&P methodology. For example, he cites obsolete criteria and fails to consult the relevant criteria and fails to address the business risk side of the methodology that I explained above, which is an integral part of any credit analysis. Because of these failures, he does not calculate the core financial metric accurately.

[5] Direct Testimony and Exhibits of Christopher C. Walters on behalf of Federal Executive Agencies, (Oct. 2, 2020), *Section IV.J. Financial Integrity*, pp. 53-56.

Q. HOW DOES THE ABSENCE OF ANY DISCUSSION OF BUSINESS RISK AFFECT MR. WALTERS'S ANALYSIS?

A. Attempting to reach a conclusion on the effect of his return recommendations based on a credit analysis that only considers credit metrics misses more than half of the credit quality equation. As I explained above, business risk is weighted more in a ratings analysis than financial risk. Mr. Walters, along with FEA witness Michael Gorman, are advocating a 70% reduction in the requested revenue deficiency[6] based on a return on equity that is below the national average.[7] Such a result would draw the attention of the rating agencies. It could potentially affect S&P's assessment of the APS business risk profile.[8]

Q. WHAT ARE YOUR CONCERNS ABOUT MR. WALTERS' INCOMPLETE CREDIT ANALYSIS?

A. Because he used outdated criteria and omitted using relevant criteria, he uses a metric that does not appear in the S&P criteria[9] and doesn't correctly calculate the relevant core credit metric of funds from operations (FFO)-to-debt.[10] Mr. Walters derives an FFO-to-debt for APS of 27%, which is far above the latest figure of 22.5% reported by S&P[11] and the S&P projection of 18-20%.[12] The wide gap between his calculation and S&P's is a solid indication that his number is wrong. This renders his analysis unsuitable as a means to opine on the Company's financial integrity.

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[6] Direct Testimony of Michael P. Gorman, p. 2.
[7] Walters, Direct at 4.
[8] *See* the outlook statement in the latest S&P credit report, where the downside ratings scenario envisions "… unfavorable regulatory outcomes such that it is inadequate to achieve its targeted revenue growth…" S&P, *Arizona Public Service Co.*, May 8, 2020.
[9] He calls it the adjusted total debt ratio which S&P does not employ anywhere in its criteria. Walters, *Direct* at 55.
[10] FFO-to-debt is defined in S&P, *Criteria |Corporates | General: Corporate Methodology: Ratios and Adjustments*, April 1, 2019. Mr. Walter's calculation appears in Attachment CCW-18DR, p.1.
[11] S&P, *Arizona Public Service Co.*, May 8, 2020, p. 6.
[12] *Id*. at 5.

Q. DO YOU HAVE ANY FUTHER COMMENTS ON ANY INTERVENORS' TESTIMONY?

A. Yes. I briefly respond to Mr. Gayer's comments later in my testimony. Other than that, I do not reference every Staff and intervenors' testimony. My failure to address statements or recommendations should not be taken as an endorsement of such statements and recommendations.

B. *Credit Ratings in the Capital Markets*

Q. WHAT ROLE DO THE RATING AGENCIES PLAY IN THE CAPITAL MARKETS?

A. Credit rating agencies provide an assessment of the creditworthiness of a company or a financial instrument to facilitate access to fixed income capital markets at the most efficient cost. The agencies publish analyses of the issuers and issuances to explain the ratings to the capital markets. Ratings are expressed in a series of letters, numbers and/or symbols to summarize the relative creditworthiness of the entity or issue. The ratings scales of the two major rating agencies on which my testimony focuses, S&P and Moody's, appear in Attachment TAS-02RB. Ratings in the BBB/Baa category and above are considered "investment-grade" by market participants. Ratings below BBB-/Baa3 are known as "speculative-grade," or colloquially "junk," ratings. Because some investors are precluded from holding speculative-grade issues, the difference between investment-grade and speculative-grade ratings is stark and is recognized as such by rating agencies and market participants.

Q. WHICH PARTICIPANTS IN THE CAPITAL MARKETS CONSULT CREDIT RATINGS?

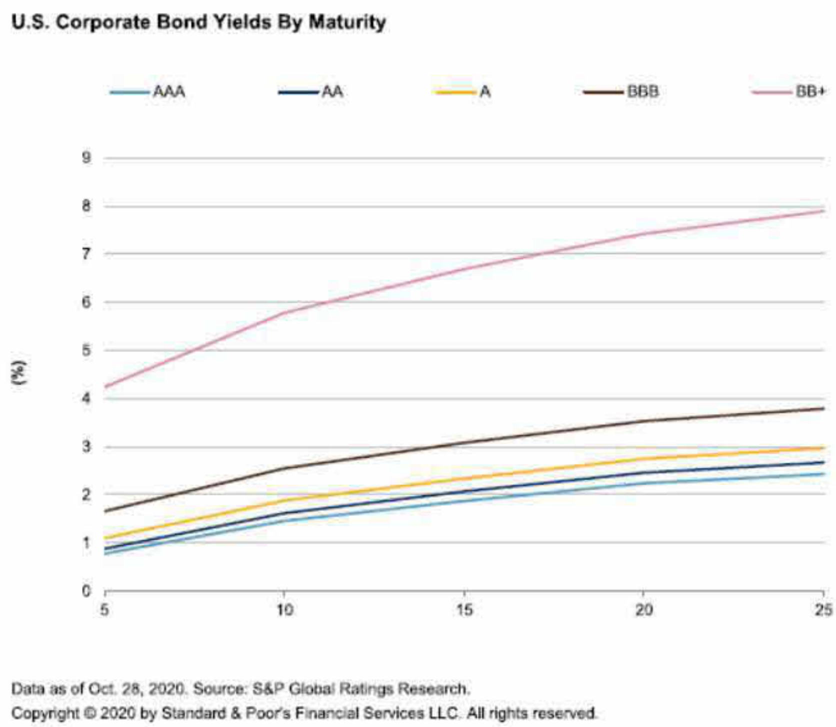
A. Investors use them to assist their investment decisions: which companies to invest in and the price (yield) that they will charge to lend to or invest equity in a company. Ratings are helpful because they are based on a consistent approach to assessing risk across time, industries and types of issuers. Because rating agencies are independent and objective but also have unique access to confidential information from issuers, ratings are also an effective solution to the familiar problem identified by economists as asymmetric information. Ratings therefore lubricate the function of raising capital. Beyond raising capital, ratings enhance the liquidity of the secondary market for securities by providing consistent and up-to-date credit assessments of issuers that buyers and sellers can use to assist their trading decisions.

Q. IF RATINGS ARE DESIGNED TO MEET THE NEEDS OF INVESTMENT PROFESSIONALS AND FINANCIAL INTERMEDIARIES LIKE BANKERS, WHY SHOULD THE ACC CONSIDER THE EFFECTS OF ITS ACTIONS ON APS'S CREDIT RATINGS?

A. Credit ratings have a direct effect on utility customers and the bills they pay.

Q. HOW DO CREDIT RATINGS AFFECT UTILITY CUSTOMERS AND THE BILLS THEY PAY?

A. Ratings affect a utility's cost of capital, a major component of the cost of service, by influencing investor perceptions of a utility's risk. That is evident on the cost of debt, where we see a correlation between bond yields and ratings:



Source: S&P, Ratings Direct, *Credit Trends: U.S. Corporate Bond Yields as of October 28, 2020*, October 29, 2020

It does not end with bondholders and other fixed-income investors. Equity investors, i.e., shareholders, look to ratings to guide their investment decisions, too. Many of the investor calls and interactions I experienced at S&P were with equity analysts and private equity investors as well as fixed-income professionals. Since the equity side of the balance sheet also uses ratings for guidance, especially when they are upgraded or downgraded, the cost of equity is another area where ratings are consequential.

Ratings also affect a utility's access to capital, especially during times of financial system stress. Stable and ideally improving ratings are essential to attracting capital at a reasonable cost. Maintaining strong ratings, not just adequate ratings, is vital to utilities because of the essential and quasi-public nature of the service they provide. Ready access to the capital they need in all market conditions is necessary to achieve the level of reliability and support for the local economy that they must offer at all times.

A by-product of the nature and design of the ratings system is that regulators ought to take as much interest in credit ratings as any investment banker or analyst. The combination of the long-term and independent nature of credit ratings make them an ideal touchstone for utility regulators to use to help navigate through the many decisions they must make in the course of balancing the various stakeholder interests that come before them.

Q. CAN YOU DEMONSTRATE THE BENEFITS THAT BETTER CREDIT RATINGS BRING TO CUSTOMERS?

A. Yes. The history of APS's ratings offers the parties a vivid, real-life example of how attention to credit quality is in the customers' best interests. A full understanding of where the Company has been from a credit quality standpoint can help us evaluate whether to support further actions to maintain ratings.

Q. WHAT HAS BEEN THE COMPANY'S RECENT EXPERIENCE WITH ITS CREDIT RATINGS?

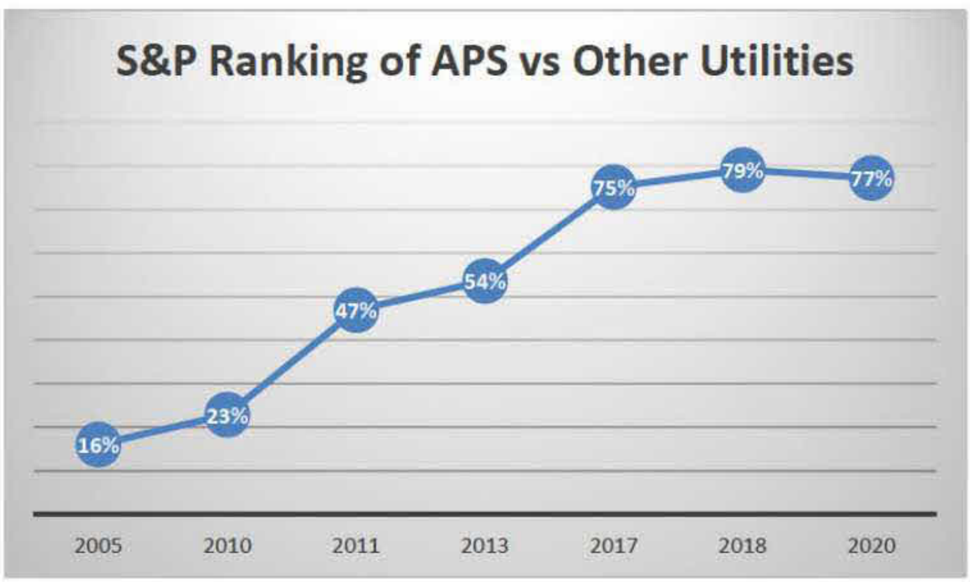
A. Consistently upward. To show the credit quality improvement clearly, I chose to concentrate on the history of one agency's ratings.[13] S&P's ratings on APS have climbed from "BBB-," on the cusp of a speculative-grade (or "junk") rating, into the "A" category ("A-") in the last decade. The work that went into the ratings upgrades goes back even further when S&P first downgraded APS to "BBB-" at the end of 2005. To summarize, S&P's concerns about the Company's regulatory risk and operating risk led to the "BBB-" rating, and by focusing on reducing both kinds of risk, in conjunction with some progress in financial performance, APS has restored its credit quality to a level not seen since the 1980s. The business and financial risk containment that S&P identified throughout this period was

[13] Moody's ratings on APS have also improved over the timeframe I analyzed.

accompanied by recognition of improvement in APS's management and governance, as well as improved timeliness of cost recovery due to shortened timeframes to complete rate cases as well as new adjustment mechanisms.

Q. HOW DO WE KNOW THAT THE RATINGS UPGRADES ARE TIED TO THE COMPANY'S PERFORMANCE AND NOT JUST PART OF A LARGER TREND?

A. One reason I tracked the S&P ratings is that it publishes rankings of the utilities that it rates. The chart below is a dramatic illustration of APS's improving credit quality, moving from near the bottom of its peers to near the top. The figures in the chart represent the position on APS in the S&P ranking list in which it appeared that year, expressed as a percentile. The rankings make clear that APS earned the upgrades by distinguishing itself among industry participants by effective risk management.



Source: S&P, North American Electric, Gas and Water Regulated Utilities – Strongest to Weakest

Q. CAN YOU SHOW THAT APS'S CUSTOMERS WERE BENEFICIARIES OF THE RECORD OF RATINGS IMPROVEMENTS?

A. Yes. I performed an analysis of the interest expense savings that will directly benefit APS's customers as a consequence of the rating improvements. I estimate that the pre-tax interest savings of APS long-term debt issuances since the S&P upgrades began in 2011 will total about $1.9 billion over the lifetime of the debt. The direct customer benefit will continue to accumulate as the years unfold.

The lower interest cost for long-term debt is only the beginning of the benefit to customers. My analysis does not include:

- savings from interest on short-term debt and variable-rate debt, which are more difficult to accurately identify;

- the savings from other types of capital, such as common equity, that also benefit from the lower risk profile that the rating improvements were based upon;

- the interest savings that resulted from the Company's ability to redeem high-cost debt early to take advantage of the lower cost of issuing replacement debt at lower rates; and

- the "qualitative" benefits that better ratings can generate for the Company and its customers. Better access to capital on reasonable terms in all types of economic and capital market conditions, especially in financial crises and other periods of market stress, has already been mentioned. Stronger credit ratings also facilitate and lower the cost of transactions with third parties, from simple, day-to-day trade with suppliers that shows up on O&M expense to the cost of purchased power and long-term agreements with generators that lean on the Company's balance sheet. These, too, are more difficult to quantify, but I believe that qualitative benefits are as important in delivering reliable, clean and efficient power to customers as the more tangible quantitative benefits.

Q. ARE THESE BENEFITS AT RISK?

A. Yes. The outcome of this and future proceedings will determine whether customers will continue to realize the benefits of the Company's advantageous ratings. Moody's this year invoked a negative outlook out of concerns centered on financial metrics.[14] Fitch Ratings (Fitch), another major agency that provides credit ratings on the Company, has carried a negative outlook on the Company since 2019.[15]

Q. SIMILAR TO HOW THE CUSTOMER BENEFITS DESCRIBED ABOVE HAVE BEEN HARNESSED FROM IMPROVED CREDIT RATINGS, DOWNGRADES CAN HURT CUSTOMERS IN A NUMBER OF WAYS OVER A LONG PERIOD OF TIME. WHAT ARE THE AGENCIES CONCERNED ABOUT?

A. I pick up the primary reason as concerns over financial metrics. That is what S&P cited in its revocation of the positive outlook in 2018 and what Moody's and Fitch outline in their negative outlooks. In describing their negative outlooks, both of Moody's and Fitch cite heightened regulatory risk, and specifically this proceeding, as a key driver for their prospective ratings decisions on the Company and tie potential negative ratings actions to the outcome. Because of the direct relationship between credit ratings and rate case outcomes, adopting the APS capital structure, return on common equity and cash-flow capabilities in its rates should be given consideration in reaching a decision in this proceeding.

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[14] Moody's, *Rating Action: Moody's affirms ratings of Arizona Public Service and Pinnacle West, revises outlooks to negative*, Jan. 22, 2020.

[15] Fitch Ratings, *Rating Action Commentary, Fitch Affirms Pinnacle West Capital & Arizona Public Service's IDRs at 'A-': Outlooks to Negative*, June 26, 2019.

In turn, APS must press forward with meeting the operational challenges cited by the rating agencies, which predominantly require execution on the Company's clean energy plans. S&P noted several aspects of this operational challenge in its latest credit report: the "risk of distributed generation, the company's limited regulatory diversity, the higher operating risks of nuclear generation, and potential environmental risks associated with the company's coal-fired generation."[16] They note that the base-load sources remain around 40% of the generation capacity. With the Company's announced goal of being completely carbon-free in its generation by 2050 and the interim goal of ending all coal-fired generation by 2031, it has set for itself an ambitious operating challenge. It will produce more benefits for its customers and Arizona and align with the growing ESG-mindedness[17] of the credit rating agencies, but it will also stress its financial position. Further progress on both sides of the credit analysis will be necessary to preserve ratings in the face of this negative sentiment.

C. *Capital Market's Effect on Credit Ratings*

Q. YOU EXPLAINED HOW RATINGS PLAY A ROLE IN THE CAPITAL MARKETS. DO THE CAPITAL MARKETS PLAY A ROLE IN CREDIT RATINGS?

A. Yes. It is a two-way street. An issuer's ability to access capital is an important element in credit analysis, especially for utilities. As Moody's states in its utilities methodology, "Liquidity and access to financing are of particular importance in this sector. …. Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility."[18]

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[16] S&P, *Arizona Public Service Co.*, May 8, 2020, p. 4.
[17] ESG is shorthand for "Environmental, Social, and Governance," a group of risks that the agencies increasingly look to evaluate as vital to understanding an issuer's overall risk profile.
[18] Moody's, *Rating Methodology: Regulated Electric and Gas Utilities*, Nov. 4, 2019, p. 25.

Q. WHAT IS NECESSARY IN THE REGULATORY PROCESS TO GIVE DEBTHOLDERS AND RATING AGENCIES CONFIDENCE THAT A UTILITY WILL BE ABLE TO ACCESS CAPITAL ON REASONABLE TERMS FOR THE BENEFIT OF CUSTOMERS?

A. First and foremost, investors look for a regulatory jurisdiction that features a fair and transparent ratemaking process that they can evaluate for its capacity to allow a utility a reasonable opportunity to earn its cost of capital. I covered this in more depth in my discussion of business risk above and in more depth in the next section. This aspect of regulation supports access to debt capital, which is an obvious concern to the rating agencies, but when followed it also underpins good access to equity capital that is equally important to assessing utility credit quality.

Q. WHY DO RATING AGENCIES CARE AS MUCH ABOUT THE TREATMENT OF SHAREHOLDERS AS THEY DO OF DEBTHOLDERS?

A. Weak or costly access to equity capital can lower ratings because it provokes greater reliance on debt to fund capital expenditures. In other words, more leverage. Additionally, credit metrics will suffer as low returns constrain cash flow and earnings.

Q. HAVE YOU OBSERVED ANY RECOMMENDATIONS IN THIS PROCEEDING THAT YOU THINK WOULD HARM CREDIT QUALITY IN THIS WAY?

A. Yes. The casual and arbitrary recommendation of Intervenor Richard Gayer[19] to eliminate or cut the APS common dividend would, if acted upon, alarm investors and rating agencies. I believe an unnecessary dividend reduction would cause a negative ratings reaction because it would make investors question the dependability of the regulatory environment in Arizona. In accordance with good corporate governance and risk management principles, dividend policy and

[19] Intervenor Richard Gayer's Prepared Direct Testimony (Sept. 22, 2020) , p. 2.

decisions on the timing and level of dividends are best left with the body that is legally and sensibly charged with overseeing them, the issuer's Board of Directors.

Q. WHY DO YOU CHARACTERIZE THE RECOMMENDATION AS ARBITRARY?

A. Witness Gayer does not substantiate his recommendation with any analysis. It appears to be based on his mistaken belief that the requested rate increase is directly connected to the level of dividends that are paid by APS. Being unfamiliar with finance fundamentals, Mr. Gayer seems to think that a temporary suspension of the regular APS common dividend would save customers money.

Q. WHAT IS THE FUNDAMENTAL PROBLEM WITH MR. GAYER'S POSITION?

A. In his testimony he states:

> …APS does not need a rate increase at this time, especially when thousands of its customers are suffering from the impact of COVID-19 on their health and, more importantly in this context, their ability to pay APS' high bills. …. The $184 Million increase sought by APS amounts to about half of its anticipated dividends to be paid to PNW's shareholders of its common stock in 2021. APS customers should not be required to fund PNW's dividends.[20]

Mr. Gayer is wrong in assuming that APS customers fund the common dividend. Shareholders pay the dividend out of shareholder funds.

Q. CAN YOU SHOW THAT COMMON DIVIDENDS ARE PAID WITH SHAREHOLDER FUNDS?

A. Yes. The stock price of a publicly-traded company will be reduced by the amount of the dividend on the date a shareholder is no longer entitled to participate in a dividend payment.[21] Denying the requested rate increase on any basis other than

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[20] Gayer at 6.

[21] That date is called the ex-dividend date. As explained on a basic financial website that is easily accessible to anyone with internet access, "Stock market specialists will mark down the price of a stock on its ex-dividend date by the amount of the dividend. For example, if a stock trades at $50 per share and pays out a $0.25 quarterly dividend, the

sound regulatory and financial principles and "paying" for the denial by disrupting the orderly payment of regular dividends though an arbitrary mandate would not benefit customers. It would harm them by prompting an adverse reaction from investors and rating agencies.

Q. WHY WOULD INVESTORS REACT NEGATIVELY TO A DISRUPTION IN THE DIVIDEND?

A. The arbitrary nature of the action alone would lead them to assign more regulatory risk to APS than they do now. Rating agencies value stability and transparency in the regulatory arena.[22] Investor reaction would be tied to a finance concept known as the signaling effect. As explained in an academic textbook, "When a firm increases its dividend, it sends a positive signal to investors that management expects to be able to afford higher dividends for the foreseeable future. Conversely, when managers cut the dividend, it may signal that they have given up hope that earnings will rebound in the near term and so need to reduce the dividend to save cash."[23] In other words, investors and rating agencies would view a regulator's decision to try to force a utility to cut its dividend as a signal that regulatory risk was worsening to the detriment of future earnings and cash flow stability. Lower ratings would result, in my opinion, and customers would thereby pay for that intrusion into APS's dividend policy through a long-term increase in the cost of capital.

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stock will be marked down to open at $49.75 per share." Zack's, *How Does the Stock Price Change When a Dividend Is Paid?* Feb. 19, 2019, found at https://finance.zacks.com/stock-price-change-dividend-paid-3571.html.

[22] See my discussion of the effect of regulatory risk on ratings below.

[23] Berk and DeMarzo *Corporate Finance: The Core, Fourth Edition*, Pearson Education, 2017, Chapter 17, Section 6, "Signaling with Payout Policy."

III. THE EFFECT OF REGULATORY ENVIRONMENT ON CREDIT RATINGS

A. *The Importance of a Utility's Regulatory Environment*

Q. WHY IS REGULATORY RISK A CRUCIAL INPUT IN THE CREDIT ANALYSIS OF A UTILITY?

A. Regulatory risk for a utility is analogous to the competitive environment of an unregulated corporate issuer. The influence of a company's competitive position on its credit quality will vary depending on the nature of its industry and the competitive dynamics of its business model. Some industries have products or services that can differentiate the firm from competitors. Others sell a product or service that is nearly identical, a so-called commodity business. Some firms are capital-intensive, in that they must invest heavily in order to produce the product they sell. Utilities share some of those attributes in varying degrees, but the characteristic that defines the credit profile of a utility is regulation. Its importance can be seen in S&P's breakdown of the weight in the business risk analysis given to what is generically called competitive advantage in the table below and for utilities is called regulatory advantage:[24]

Table 12

Competitive Position Group Profiles (CPGPs) And Category Weightings

	--(%)--					
Component	Services and product focus	Product focus/scale driven	Capital or asset focus	Commodity focus/cost driven	Commodity focus/scale driven	National industries and utilities
1. Competitive advantage	45	35	30	15	10	60
2. Scale, scope, and diversity	30	50	30	35	55	20
3. Operating efficiency	25	15	40	50	35	20
Total	100	100	100	100	100	100
Weighted-average assessment*	1.0-5.0	1.0-5.0	1.0-5.0	1.0-5.0	1.0-5.0	1.0-5.0

*1 (strong), 2 (strong/adequate), 3 (adequate), 4 (adequate/weak), 5 (weak). [25]

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[24] S&P, *Key Credit Factors for The Regulated Utilities Industry*, Dec. 4, 2019, paragraph 20.

[25] S&P, *Criteria | Corporates | General: Corporate Methodology*, Apr. 30, 2020, Table 12, p. 22.

Even areas that do not explicitly touch on regulatory behavior, like scale and operating efficiency, are subsumed in the central question of utility regulation: cost recovery, including full recovery of its cost of capital through a reasonable authorized return on equity. Thus, in Moody's utility methodology, regulatory risk constitutes fully 80% of business risk.[26] It is nominally 60% for S&P, as seen above, but in my experience the impact is much greater and effectively approaches the Moody's weighting.

Q. DOES THAT FULLY CAPTURE THE INFLUENCE OF REGULATION ON A UTILITY'S CREDIT PROFILE?

A. No. We know that regulators have a profound impact on financial results. That means regulators act on both sides of the credit rating equation. The details of establishing rates and the level and timing of cost recovery has a direct effect on a utility's ability to earn its authorized return on equity (ROE) and produce enough earnings and cash flow to support its ratings. A fair rate of return, including a capital structure that offers more risk protection to bondholders and other creditors, are features of a credit-supportive regulatory environment. Completing the circle, the same regulatory actions that affect a utility's ability to earn a competitive ROE also have a compounding effect on business risk, thereby magnifying the ratings impact of regulatory decisions and behavior that fall outside expectations or norms.

B. *Evaluating a Utility Regulatory Environment*

Q. WHAT'S THE FIRST STEP IN ASSESSING REGULATORY RISK FOR A RATINGS ANALYST?

A. Both S&P and Moody's begin with the basic regulatory framework, including (1) the legal foundation for utility regulation, (2) the ratemaking policies and procedures that determine how well the utility is afforded the opportunity to earn a reasonable return with a reasonable cash component, and (3) the history of

[26] Moody's, *Rating Methodology, Regulated Electric and Gas Utilities*, Nov. 4, 2019, p. 4.

regulatory behavior by the governing bodies applying those laws, policies and procedures.

Q. AFTER THE BROAD FRAMEWORK IS ANALYZED, HOW IS REGULATORY RISK DETERMINED?

A. S&P and Moody's next examine the mechanics of regulation, particularly the rate-setting process. Rate cases take up much of the analysis, but the totality of a utility's tariff schedule is assessed to capture the effect on business risk of revenues generated outside base rates. Creditors, and therefore rating agencies, attribute less risk to tariff provisions, such as adjustor and adjustor mechanisms, that operate outside the rate case cycle and adjust rates frequently to match revenues with expenses. A flexible tariff regime minimizes regulatory lag. That kind of rate flexibility is almost universal across the utility industry and helps to stabilize earnings and cash flows. It embodies good risk management, which lowers risk to the benefit of the utility and its customers.

Q. WHAT OTHER FORCES ENTER INTO THE ASSESSMENT OF REGULATORY RISK?

A. The nature and pace of the process of recognizing an incurred cost as recoverable through rates is always going to be the paramount consideration for determining regulatory risk. That said, the supplemental factor of the political aspect of utility regulation is brought into the analysis to discern the broader risk of the potential for abrupt changes to the prevailing regulatory approach. This factor is implied in the Moody's methodology, where it appears under the initial framework step.[27] S&P highlights political risk by carving it out as a separate item in its criteria, dubbed "Regulatory independence and insulation."[28] The analytical approach to political considerations was further explained in a subsequent commentary: "Bondholders should recognize that utility regulation harbors political as well as

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[27] *Id.* at 7.

[28] S&P, *Key Credit Factors*, Dec. 4, 2019, paragraph 27.

economic risks. Therefore, how politics could influence regulation helps [S&P] evaluate a regulatory environment. …. The primary factor in this part of our analysis is the regulators' (and, when relevant, the judicial body that reviews the regulators' decisions) political independence."[29]

Overlaying all the analysis of regulatory risk is the rating agency's view of the utility's ability to manage regulatory risk. This is again less explicit in the Moody's methodology, but S&P delineates the distinction between the regulatory environment and the individual utility's regulatory risk in its criteria.[30]

Q. ARE THE MECHANICS AND POLITICS OF REGULATION THE ONLY CONSIDERATIONS THAT GO INTO DETERMINING REGULATORY RISK?

A. No. Investors and therefore rating agencies also value consistency and transparency in regulation. Rating agencies rate many types and tenors of fixed income securities, but the quintessential instrument that drives the analysis is a long-term bond. They regard debtholders who extend credit over long periods as their primary audience and strive to rate long-term debt as accurately as possible over the longest timeframe as possible. Utilities fund capital expenditures with long-dated maturities to match the life of the assets, and utility investors value ratings that are forward-looking and stable. Regulatory frameworks and institutional behavior that allow rating agencies to confidently project future cash flows and debt leverage will inevitably be accorded a better business risk profile. Predictability facilitates the ability to accurately assess risk over the debt's term and improves the ability of the company to manage its business activities and capital program for the long-term benefit of customers.

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[29] S&P, *Assessing U.S. Investor-Owned Utility Regulatory Environments*, May 18, 2015, p. 7.
[30] S&P, *Key Credit Factors*, para. 29-30.

Rating agencies therefore place inordinate emphasis on concepts that can be grouped into two important analytical factors when evaluating regulatory risk: certainty and timeliness. Certainty is paramount because of the long-term nature of their analysis, as noted immediately above, and because ratings are forward-looking. Greater confidence in the future actions and behavior of a utility's regulators will lead to better ratings due to the stability and accuracy of the analyst's forecasts that a rating committee reviews. Timeliness is the second concept that rating agencies pay substantial attention to. For the most part, timeliness refers to the recognition of costs in rates. As noted earlier, regulatory lag is tracked closely by the agencies due to its effect on cash flow. The importance of tariff adjustment clauses cannot be overstated. It also is reflected in the regard that agencies have for how the ratemaking process is managed. S&P summed it up in its criteria: "We base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability, efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return. Our view of these four pillars is the foundation of a utility's regulatory support."[31]

C. *Improving the Regulatory Environment*

Q. GIVEN THE IMPORTANCE OF REGULATION AND THE RATING AGENCIES' ANALYTICAL APPROACH TO GAUGING REGULATORY RISK, WHAT DO YOU SEE AS THE IMPLICATIONS FOR APS, THE ACC, AND CUSTOMERS FROM THE OUTCOME OF THIS PROCEEDING?

A. I see several implications for the parties in this case from a fuller understanding of credit ratings, their importance to customers and rating agency analysis of utility credit quality. I see some of the most impactful pieces as:

[31] *Id*. at para. 22.

- ROE and capital structure;
- Determination of prudence and recovery of Four Corners Selective Catalytics Reduction investment and the Ocotillo Modernization Project, and their respective deferrals; and
- Prevent an increase in regulatory lag by authorizing more timely recovery of APS's future clean energy investments.

Q. HOW WOULD SUPPORT FOR A CLEAN ENERGY ADJUSTOR BY THE STAKEHOLDERS INVOLVED IN THE REGULATORY OVERSIGHT OF APS IMPROVE THE COMPANY'S REGULATORY RISK?

A. The eventual adoption of a clean energy adjustor would extend the benefits that customers are already experiencing from the risk reduction effects of Arizona's use of adjustor mechanisms. Adjustors are prominently cited by S&P[32] and Moody's[33] as a credit strength. By working off the solid base of progressive ratemaking that has been established over the years, acknowledgement of the magnitude of the clean energy transformation, and a regulatory response to help effectuate the transformation would be a natural advancement of the existing framework. I believe the proposed adjustor would reinforce the long-term positive direction of the entire Arizona regulatory climate in the minds of investors and rating agencies.

Q. DO YOU THINK ATTITUDES ABOUT REGULATORY RISK IN ARIZONA ARE SUPPRESSING APS'S CREDIT RATINGS?

A. Yes. Arizona has a relatively low standing with S&P and in the investment community with regard to regulatory risk.[34] APS's business risk is nevertheless

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[32] S&P, *Arizona Public Service Co.*, May 8, 2020, p. 4.
[33] Moody's, *Arizona Public Service Company*, Jan. 27, 2020, p. 3.
[34] Due to its two-pronged approach to regulatory risk, S&P assesses regulatory jurisdictions as part of the credit analysis of utilities. Arizona is in the second-lowest category among the five that S&P uses to rank North American jurisdictions. S&P, *U.S. and Canadian Utility Regulatory Updates and Insights: June 2020*, June 8, 2020. Arizona

assessed as low (i.e. credit-positive) by Moody's (solid "A" scores across the board on regulatory factors)[35] and S&P (an "Excellent" business risk profile, the highest attainable among six categories). Both agencies have misgivings about the Company's business risk, however. Moody's is focused on regulatory risk, noting that a rating downgrade could result "if the Arizona regulatory environment becomes less credit supportive or predictable, such as through an adverse rate case ruling or cost recovery disallowances…"[36] Given its view that the Arizona regulatory environment could restrict credit quality, S&P similarly cautions about "unfavorable regulatory outcomes" in its downside outlook scenario.[37]

I believe an APS with authorized timely recovery of clean energy investments, in addition to its existing adjustors, would improve investor and rating agency perceptions of regulatory risk. All those stakeholders, and especially customers, have benefitted from the advancements in ratemaking procedures and mechanisms through dramatically higher credit ratings. Taking the next step would preserve the gains from the transformation of APS from near junk-bond status to among the best integrated electric utilities in the U.S.

IV. <u>CREDIT RATING ENVIRONMENT AND CONCLUSIONS</u>

Q. WHAT IS THE CURRENT STATE OF THE CREDIT RATING ENVIRONMENT FOR UTILITIES?

A. This case is unfolding against a backdrop of economic stress from the sudden onset of the COVID-19 pandemic and the continuing effect of tax reform on the financial position of U.S. utilities. While the crisis has a different character than the last major disruption in 2008-2009, in some ways it harbors greater risk because of the

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is in roughly the lower third of the most widely accepted ranking among investors, published by a separate arm of S&P. S&P Global Market Intelligence, *RRA Regulatory Focus, State Regulatory Evaluations*, May 19, 2020.

[35] Moody's, *Arizona Public Service Company*, p. 7.

[36] *Id*. at 2.

[37] S&P, *Arizona Public Service Co.*, May 8, 2020, p.3

unprecedented nature of the cause and sheer unpredictability of the coronavirus spread and the world's reaction to the threat.

Q. HAS THE MACROECONOMIC AND CAPITAL MARKET ENVIRONMENT HAD AN EFFECT ON THE RATING AGENCIES' OUTLOOK ON THE UTILITY SECTOR?

A. Yes. S&P had returned the utilities industry to a stable outlook for 2020 after being more negative in past years, but they revised the industry outlook back to negative in April after their forecast of the economic effect of the coronavirus outbreak showed a deep, worldwide recession.[38] Numerous utilities with credit metrics at the edge of downgrade triggers combined with pre-existing environmental pressures and COVID-19 to tip the outlook downward. In their view, COVID-19 concerns center on utilities with large commercial and industrial customer bases and those with significant commodity exposure in non-utility portions of their portfolios.[39] S&P pointed to capital spending cuts to mitigate the risk of widespread credit deterioration in a severe recession, with dividend cuts the next line of defense.[40] S&P analysts have also stressed the need for effective regulatory responses[41] and utility responses[42] to COVID-19 pressures on credit quality.

Moody's has retained its stable outlook on the industry but increasingly highlighted the downside risks in a series of published comments that reveals its growing unease with that outlook. After initially envisioning credit resilience despite coronavirus disruptions[43] and dismissing greater leverage for liquidity purposes as

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[38] S&P, *COVID-19: The Outlook for North American Regulated Utilities Turns Negative*, April 2, 2020.
[39] *Ibid*., p. 7.
[40] *Ibid*., p. 8.
[41] S&P, *Regulatory Responses to COVID-19 Are Key to Utilities' Credit Prospects*, May 20, 2020.
[42] S&P, *North American Regulated Utilities Face Tough Financial Policy Tradeoff to Avoid Ratings Pressure Amid the COVID-19 Pandemic*, May 11, 2020.
[43] Moody's, *Sector Comment: Utilities demonstrate credit resilience in the face of coronavirus disruptions*, Mar. 18, 2020.

merely temporary,[44] they proceeded to explain that, while they do not expect to see widespread reduction in utility dividends, slowed dividend growth may be necessary if the disruption becomes a prolonged downturn.[45] Then, after expressing confidence that regulatory support would protect utility credit quality or even be a credit positive,[46] they realized that the economic devastation from COVID-19 would depress consumer tolerance for rate increases[47] and authorized returns[48] and conceded that outcomes will vary among jurisdictions.[49]

Q. WHAT ARE YOUR CONCLUSIONS ABOUT THE POTENTIAL OUTCOME IN THIS PROCEEDING?

A. The ACC is faced with important decisions for APS in this case that could have far-reaching consequences for its credit ratings and the regulatory environment for all Arizona utilities. The record of ratings upgrades that the Company was able to achieve with the Commission's support in the decade following its 2005 descent to the edge of investment-grade ratings has stalled. We are now experiencing an unprecedented type of economic crisis that has stressed the economic, political and social fabric of the nation. At the same time, APS has embarked on bold and innovative programs to accelerate its transformation to a clean, sustainable energy provider with an increased focus on its customers' needs in the areas of demand management and electric vehicles. That transformation amid the challenging economic and market conditions prompted a negative outlook by both Moody's and the aforementioned Fitch report.[50] The answer to those investor concerns is in

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[44] Moody's, *Sector Comment: FAQ on credit implications of the coronavirus outbreak*, Mar. 26, 2020.
[45] Moody's, *Sector Comment: Dividends a major source of cash if coronavirus downturn is prolonged*, Apr. 6, 2020.
[46] Moody's, *Sector Comment: Coronavirus outbreak delays rate cases, but regulatory support remains intact*, Apr. 6, 2020.
[47] Moody's, *Sector Comment: Coronavirus-fueled rise in unemployment will limit consumer tolerance for rate hikes*, Apr. 17, 2020.
[48] Moody's, *Sector Comment: Continued decline in ROEs to heighten pressure on financial metrics*, Apr. 17, 2020.
[49] *Ibid.*, p. 6.
[50] Moody's, *Rating Action*, Jan. 22, 2020.

the short run to authorize the requested revenue requirement to promote ratings stability and investors' views of the Arizona regulatory environment. Adding a clean energy adjustor mechanism in the future would lower regulatory risk for APS, with all the customer benefits that go with it.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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Experience

Utility Credit Consultancy LLC **Boston, MA**

Principal May 2018 - Present

Founded a consulting firm to provide utilities with expert witness services and advice on capital market strategies. Specialize in capital markets issues, credit rating advisory, and hybrid securities.

Boston University **Boston, MA**

Lecturer January 2017 – June 2020

Adjunct faculty member in the Questrom School of Business, Department of Finance. Taught advanced undergraduate finance courses covering capital markets, monetary and economic policy, and corporate finance.

S&P Global Ratings **New York, NY and Boston, MA**

Senior Director	April 2014 - May 2018
Director	April 2000 - April 2014
Associate Director	March 1997 - April 2000

Sector Specialist on the Global Infrastructure Ratings North American Utilities team. Performed credit surveillance of utilities, pipelines, midstream energy, and diversified energy companies. Chaired most team rating committees. Wrote credit reports and commentaries and led outreach efforts to investors and the regulatory community, including speeches and training seminars. Lead analytical role developing global rating criteria for utilities, master limited partnerships, and hybrid capital securities.

Electric Utility Research Inc (defunct), San Francisco, CA

Senior Vice President May 1996 - March 1997

Edited and contributed to an investor newsletter covering the electric utility industry

Sithe Energies Inc. **New York, NY**

Manager, Regulatory Affairs November 1993 - May 1996

Managed state regulatory matters for a major independent power company. Coordinated interventions in regulatory proceedings. Assisted in identifying development opportunities. Participated in investor relations activities.

Regulatory Research Associates **Jersey City, NJ**

Vice President	October 1993 - November 1993
Senior Analyst	August 1989 - October 1993
Analyst	August 1985 - August 1989

Analyzed and reported on actions by state regulators affecting the financial status of electric, gas, and telephone utilities for a firm that provided research to the Wall St. community. Contributed to the firm's sell-side research.

Education

J.D., Texas Tech University School of Law, Lubbock, TX	May 1984
B.B.A., Texas Christian University, Fort Worth, TX	May 1981

Professional Affiliations & Other Activities

Executive Advisor, Concentric Energy Advisors, Marlborough MA

Chartered Financial Analyst

Wall Street Utility Group

Fixed Income Analysts Society Inc

Society of Utility and Regulatory Financial Analysts

Other Activities

Board of Directors, The Good Shepherd School, Charlestown, MA

MOODY'S INVESTOR SERVICE	S&P GLOBAL RATINGS
Aaa	AAA
Aa1	AA+
Aa2	AA
Aa3	AA-
A1	A+
A2	A
A3	A-
Baa1	BBB+
Baa2	BBB
Baa3	BBB-
Ba1	BB+
Ba2	BB
Ba3	BB-
B1	B+
B2	B
B3	B-
Caa1	CCC+
Caa2	CCC
Caa3	CCC-
Ca	CC
C	C
D	D